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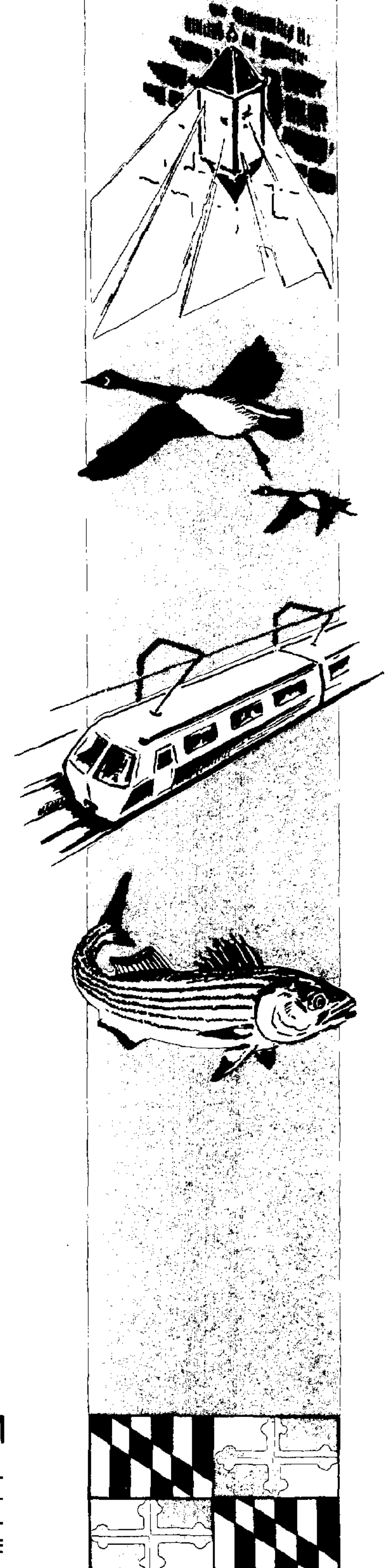

POWER PLANT CUMULATIVE ENVIRONMENTAL IMPACT REPORT

February 1982

AND POWER PLANT SITING PROGRAM
OF NATURAL RESOURCES ■ DEPARTMENT OF HEALTH AND MENTAL
DEPARTMENT OF ECONOMIC AND COMMUNITY DEVELOPMENT ■ DE-
STATE PLANNING ■ DEPARTMENT OF TRANSPORTATION ■ DEPART-
RICULTURE ■ COMPTROLLER OF THE TREASURY ■ PUBLIC SERVICE

JAMES B. COULTER
SECRETARY

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DEPUTY SECRETARY

STATE OF MARYLAND
DEPARTMENT OF NATURAL RESOURCES
TAWES STATE OFFICE BUILDING
ANNAPOLIS 21401

March 19, 1982

The Honorable Harry Hughes
Executive Department
Office of the Governor
State House
Annapolis, MD 21404

Dear Governor Hughes:

The 1981 Cumulative Environmental Impact Report prepared pursuant to the Maryland Power Plant Siting Act is forwarded. The Report is an analysis of the cumulative impact of electric power plants on Maryland's environment.

Eighty-seven percent of Maryland's electricity is currently generated using coal and nuclear fuels and it is likely that coal will displace even more oil by the end of the decade. Increased coal use with its concommitant potential for air, groundwater and surface water impacts from combustion, transport and disposal will require thorough investigation in determining appropriate conditions on the construction and operation of coal-fired power plants.

Monitoring results show that nuclear plants (Calvert Cliffs, Peach Bottom and Three Mile Island) are not exceeding regulatory constraints. Establishment of a functioning system by the federal government for handling spent nuclear fuel and high level radioactive waste is critical for the continued operation of nuclear power plants in the United States beyond the early 1990's. The federal government should be encouraged to determine methods and locations for these wastes as soon as possible.

The information contained in this report demonstrates the importance of the State's capability to collect and analyze technical data to insure that Maryland continues to have an adequate supply of electricity without degrading its natural resources or the human environment.

Sincerely yours,

James B. Coulter

James B. Coulter

JBC/kss
Enclosure

PPSP-CEIR-3

POWER PLANT

CUMULATIVE ENVIRONMENTAL

IMPACT REPORT

FEBRUARY 1982

Maryland Department of Natural Resources

Comments and requests for additional copies should be addressed to Editor, Cumulative Environmental Impact Report, Power Plant Siting Program, Maryland Department of Natural Resources, Tawes State Office Building, Annapolis, Maryland 21401

FOREWORD

The Cumulative Environmental Impact Report is issued every two years as required by the Maryland Power Plant Siting Act. It is a compilation of all studies relating to the cumulative impact of power plants on Maryland's environment. Chapters were prepared under contract with principal responsibility for content and completion vested in a member of the Power Plant Siting Program Staff. Principal authors and their PPSP staff counter parts are herewith acknowledged for their contribution to this effort:

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Chapter X - Tom Magette, PPSP

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I gratefully acknowledge Dr. Jorgen Jensen for his contributions in putting this publication together; Karen Spencer and Daphne Heaphy for their patient, competent, and cheerful typing of numerous drafts; the many others without whose contributions this publication could never have been completed. Thank you.

P E Miller

Paul E. Miller
Editor, CEIR-III

SUMMARY

Chapter I - Power Demands in the State of Maryland

For decades prior to the early 1970's energy consumption grew steadily in the United States while energy prices remained stable. The most important factor sustaining this pattern was the availability of inexpensive oil, imported mainly from the Middle East. These trends were brought to an abrupt end in 1973 by the Arab oil embargo and subsequent events. Skyrocketing prices and limited availability brought about sharp declines in energy usage. Thus by 1980 the energy consumption was only marginally higher than in 1973.

The transient effects of the 1973 embargo have largely died out, and new trends in the pattern of energy production and consumption have emerged. The long range annual growth rate for total energy consumption has fallen from 4.1 percent for the 1960-1973 period to an expected 1.6 percent for the 1980-1995 period.

Prior to 1973 the national annual growth rate for electric energy was about 7.3 percent. It is projected that the demand will grow by 3.2 percent per year through 1995, while the demand for the other energy forms will stagnate. Increased demand for electric energy coupled with increased coal utilization by the industry is largely responsible for the proportional increase in coal usage over other primary fuels.

This Chapter presents a detailed discussion of the electric utility industry in Maryland. Projections of the future demand for electricity, utilizing econometric models, are presented. The total of the peak demands of the utilities serving Maryland is forecast to increase at an annual rate of 2.5% through 1990.

The potential for reduction of the growth rate of electricity demand through implementation of conservation measures and load management is discussed. Load management can be accomplished through use of devices such as radio controlled water heaters or through a ratemaking policy reflecting the time-varying marginal cost of producing electricity.

Chapter II - Power Supply in the State of Maryland

The increasing demand for energy prior to the early 1970's was met primarily by increasing natural gas and petroleum production and by higher imports of petroleum. As a consequence of the 1973 oil embargo the nation's supply of primary energy has shifted toward greater reliance on coal and nuclear energy. In 1973 oil and gas accounted for about 78 percent of the primary energy supply while coal and nuclear energy combined provided 19 percent of the supply. By 1985 it is expected that these percentages will be 62 and 33 respectively.

The pattern of electric power supply in the United States reflects the conditions of the primary energy market (slower demand growth and higher fuel prices) as well as changes in the regulatory environment. The Fuel Use Act of 1978 prohibits use of oil or natural gas as a primary fuel for new generating units and for existing units which can be converted from oil to coal. These various factors are expected to cause the nation's electric utilities to increase the use of coal and nuclear fuel from about 48 percent in 1973 to about 74 percent and about 81 percent in 1985 and 1990 respectively.

Generation capacity of utilities serving Maryland is 33 percent oil and gas fired and 66 percent from coal and nuclear. Since oil and gas fired plants are operated less often than coal and nuclear power plants, the electricity actually produced by oil and gas fired plants amounted to only 12% of the total, compared to 87% produced by coal and nuclear power plants. By 1990, installed capacity is expected to be 25 percent oil and gas fired and 70 percent fired by coal and nuclear.

The generation profile and capacity expansion plan for each of the utilities serving Maryland are presented in this Chapter. These plans provide for adequate capacity reserve margins throughout the period of the current Ten-Year Plan.

Chapter III - Air Impact

Power plants contribute about 30 percent of the particulates, about 63 percent of the sulfur oxides, and about 28 percent of the nitrogen oxides emitted by all sources in Maryland. Only negligible amounts of carbon monoxide and hydrocarbons are contributed by the power plants.

For the three major pollutants emitted by power plants, air quality shows a trend toward improvement for particulates and sulfur oxides, while the level of nitrogen oxides has been relatively constant during recent years. All areas of the State are in compliance with the National Ambient Air Quality Standards for sulfur and nitrogen oxides. A state implementation plan has been prepared to bring the Baltimore Metropolitan nonattainment region into compliance with the primary federal standards by 1982 and the secondary (and more stringent) standards by 1986.

The theoretical and experimental work on mathematical models for predicting air quality impacts is discussed in this Chapter.

Federal regulatory measures have impacted Maryland in two ways. The first relates to the "emission offsets" policy of the Clean Air Act. The State is presently exploring the establishment of an offset "market" for the Baltimore area. The second area of impact relates to coal conversion. Eight units of the Baltimore Gas and Electric Company are under "prohibition orders" which, should they become final, will prohibit burning of oil or natural gas at these units. Since six of the units are located in or near nonattainment areas for particulates the environmental consequences of these conversions must be carefully examined.

Chapter IV - Aquatic Impact

Power plants can cause aquatic impact in several ways: 1) by entraining fish eggs, larvae or other organisms into the cooling system where they will be exposed to thermal, mechanical and thermal stresses; 2) by impinging fish and crabs on intake screens; and 3) by discharging heat and chemicals into receiving waters.

Since aquatic communities generally are characteristic of the salinity zones they inhabit, the cumulative impact of power plant operations has been assessed by salinity/habitat zones.

Because of the high reproductive rates of the plankton and good tidal mixing at the existing plants in mesohaline regions of the Bay (Chalk Point, Morgantown, Calvert Cliffs and Wagner), significant depletion of plankton populations has not occurred. Ichthyoplankton is entrained by these plants, but spawning occurs throughout the Bay for the species of fish present here, so local depletions are insufficient to decrease Bay populations. Impingement totals are small compared to mortality due to other causes. In addition, efforts to reduce these totals are now underway at all major plants. Habitat modification effects, usually more subtle in nature, have minor, localized impacts as described in this chapter. Coupled together, the power plant monitoring studies show a low cumulative impact on the mesohaline environment.

The major area of concern within the tidal fresh/oligohaline region is the impact of cooling water withdrawals upon the nursery and spawning areas of striped bass and other anadromous species. Possum Point and Vienna have the highest potential for impact. The estimated maximum total annual striped bass loss would be about 1.0 percent of the adult population in the Maryland portion of the Bay.

Data collected recently at Baltimore Harbor plants show that there are abundant and diverse biota present in their vicinity. Measured impacts due to entrainment, impingement, and habitat modification are uniformly small or not present and restricted to the vicinity of the discharge. No evidence of cumulative impact on the Bay ecosystem has been found. Temporally cumulative impacts observed have been restricted to the immediate vicinity of discharge and in some cases have been beneficial rather than deleterious.

Recent data from riverine plants have revealed impacts localized to the discharge area. No cumulative river-wide effects are evident on the Potomac River. The role of the Conowingo hydroelectric facility in the decline of fisheries in the Susquehanna River remains a significant concern. Studies currently underway address this issue.

Chapter V - Radiological Impact

The nuclear power plants affecting Maryland are Calvert Cliffs, on the Chesapeake Bay (the only nuclear plant operating in Maryland), Peach Bottom, and Three Mile Island, both on the Susquehanna River in Pennsylvania. Data used in the assessment of the radiological impact of these plants come from several monitoring programs described in this Chapter. Because the amount of radioactivity released under stringent regulatory control is very small, determination of power plant impact is complicated by the problem of separating power plant effects from the background due to radioactivity from natural sources or weapons-test fallout. For instance, fall-out from weapons testing by the Chinese in 1978 introduced a dominant factor into the monitoring measurements.

Releases of gaseous and liquid effluents from the plants, and the atmospheric and aquatic distribution of radionuclides, as determined from the monitoring programs, are presented. For the Calvert Cliffs plant it was found that Sr-89 is the only radionuclide detectable in the atmosphere that can be attributed to plant releases. The impact of the very low concentrations of this element is deemed insignificant. Several power plant related bioaccumulable radionuclides (Co-58, Co-60, Zn-65, and Ag-110m) are routinely detected at low levels in Bay biota, with the exception of edible finfish. The maximum detected concentrations would result in radiation doses to man which are orders of magnitude below doses resulting from the natural radioactive sources in the Bay environment. Consumption of seafood containing the highest radionuclide concentrations measured would result in a plant-related increment of less than 0.2 percent of the dose due to the natural background.

At Peach Bottom, I-131 attributable to the plant has been detected in the air and in milk on several occasions. I-131 from the Chinese weapons test and apparently from Three Mile Island has also been detected at the same locations. Radiation doses from all these low I-131 levels are, however, well within the federal guidelines for power plant operations.

Liquid effluents containing power plant radionuclides have produced detectable concentrations (of Zn-65, Cs-134, and Cs-137) in sediments and biota of the Conowingo Pond, the lower Susquehanna River, and the upper Bay. Consumption of Conowingo Pond water and contaminated finfish exclusively at the highest radionuclide concentrations would represent about 1 percent of the natural background radiation dose.

The accident at Three Mile Island resulted in detectable, low level concentrations of Xe-133 and I-131 in air samples in Maryland. I-131 was not detected in cow's milk in Maryland nor were radionuclides attributed to that power plant detected in the Susquehanna River in Maryland. The plant is currently prohibited from discharging any accident-related water.

This chapter also discusses the radiological on-site and off-site planning required by Federal regulations.

Spent fuel is currently stored at the nuclear power plants because spent fuel reprocessing was prohibited from 1977 to 1981 in this country. Although this prohibition is now lifted it is not expected that reprocessing or off-site storage of spent fuel will be possible until middle or late 1980's. Storage of spent fuel is not considered to present a significant environmental threat. Assuming present licensed capacity, and retaining the capacity to discharge one full core, the projected date of the last refueling that can be discharged to the spent fuel pool at Calvert Cliffs is April 1990. Under the same conditions, Peach Bottom has ability to store fuel on-site until 1986 for Unit 2, and 1987 for Unit 3.

Chapter VI - Socioeconomic Impact

The construction and operation of a power plant may have significant economic and social impact upon the community where it is located. The effects include changes in population and land use patterns, traffic congestion, changes in income, employment, and business activity, as well as changes in local government tax revenues and spending. The magnitude of these changes depends on the size, location, and composition of the affected communities.

Early studies of the impacts caused by the Calvert Cliffs plant construction showed the needs for a means of predicting impacts on the predominantly rural communities which are the proposed sites for future power plants in Maryland. A computerized model was developed and subsequently used to estimate the social and economic effects of the expansion of the Vienna power plant. The plant is located on the border between Dorchester and Wicomico counties. These counties and their urban centers, Cambridge and Salisbury, will be affected.

The conclusions of this study are that: 1) the local economy can well absorb the effects of increased employment during construction; 2) the demand for additional housing can easily be met; 3) additional public services can be provided within the existing frame work; 4) traffic congestion will be minimal; 5) during the construction period neither Vienna nor Cambridge will experience significant fiscal effects while Wicomico and Dorchester counties will have a net increase in revenues, Salisbury is expected to suffer a small construction period deficit; 6) during the operating period Dorchester County will have a substantial net surplus whereas the effect on Wicomico County and the cities will be negligible.

Expansion of the Vienna plant will lead to the strengthening of Eastern Shore rail traffic because of the need for coal transport.

Chapter VII - Noise Impact

Noise associated with power plants can come from the primary generating facility, from cooling towers, from coal handling equipment, or from vehicular traffic associated with the plant operation.

A procedure for evaluating the impact of noise on people has been developed by the U.S. Environmental Protection Agency. The State of Maryland has established regulations restricting the noise levels.

The results of a noise evaluations at six proposed and existing Maryland power facilities are described in this Chapter.

Chapter VIII - Solid Waste Management

Power plant operation generate large quantities of solid waste, mainly flyash and scrubber sludge, and to a lesser extent bottom ash and boiler slag. Waste product utilization is desirable and usually possible. Bottom ash and some flyash is currently being sold for reuse. The remaining quantities are placed in managed land fills. This chapter discusses the potential problems of managing solid waste disposal.

There are no utility flue gas desulfurization systems operating in Maryland and hence no sludge disposal impact. Flyash and bottom ash disposal methods vary among the utilities. BG&E markets some of its flyash. All utilities operate land fills at various places.

Previously utilized disposal sites are currently being studied by the Power Plant Siting Program to determine if they are affecting the environment and if remedial measures are necessary.

Chapter IX - Groundwater

Four Maryland power plants use groundwater for their operation. The reduction of water available to other users and the lowering of the water level or "potentio-metric surface" surrounding the point of withdrawal is evaluated.

Withdrawal at the Calvert Cliffs and Vienna plants have no adverse effect on the aquifers involved. At the Morgantown plant the water level in the lower of the two aquifers used has dropped substantially but no other user is affected. At the Chalk Point plant the withdrawal from the Magothy Aquifer could have significant impact on other users in the area. PEPCO has indicated that future withdrawals will come mainly from new wells in the deeper Patapsco aquifer which is not tapped by other users in the areas, and which contains an adequate amount of water.

Chapter X - Transmission Lines

Construction of transmission lines has several impacts common to all major construction projects such as sediment run-off, disturbance of wild life habitats, and deforestation. In addition, electrical effects such as radio and television interference, audible noise, ozone production, and spark discharges can be present near transmission lines. Finally the presence of a transmission line may cause aesthetic impacts, possibly affecting property values.

The electric effects are only present at high voltage lines (500 KV and above) and even then only in the immediate vicinity of the line, usually within the power line right-of-way. The other effects can be minimized through judicious routing of the transmission corridor, avoiding as much as possible unique or environmentally sensitive areas.

This Chapter discusses the various factors that are important in the routing of transmission line corridors.

It is concluded that no health effects associated with transmission lines have been found. Electric effects can generally be avoided. Aesthetic impact and impact on land value have been studied and no conclusive results emerge.

Chapter XI - Cooling Towers

Salt drift from the natural draft cooling tower at Chalk Point deposits less than 8 kg/ha-month off site. This rate is below the rate at which foliar damage was evident in commercial crops (20 kg/ha-month). Predicted off-site deposition rates for the tower proposed at DP&L's Vienna expansion are less than 25 kg/ha-month and reduction in crop yield is estimated to be a few percent at the power plant site boundary and smaller off-site.

RECOMMENDATIONS

1. It is recommended that administrative or legislative methods be found to further consolidate and streamline the current regulatory procedures for power plants. When the Power Plant Siting Act was enacted in 1971, all state permits impinging on site suitability were incorporated under the Public Service Commission certificate so that there was a single regulatory proceeding for power plants in the State. Since 1971 new environmental requirements at the federal level have resulted in additional permits for water quality and solid waste disposal. Decisions on these permits are only partially incorporated in the PSC process.

2. Present requirements in law for a 10-year plan from each electric utility should be extended to 15-years. Present trends indicate that 8-10 years are required to locate, license, and construct a fossil-fueled plant and 10-15 years are required for a nuclear plant.

3. The continued disposal of low level radioactive waste and the establishment of national capability for high level radioactive waste disposal are critical to the continued operation of the Calvert Cliffs Nuclear Power Plant. Negotiations should be concluded which will allow Maryland to enter an interstate agreement for continued disposal of low level radioactive waste. After January 1, 1986, States which have concluded such regional agreements will be allowed by federal law to exclude waste from outside their region. In addition, the federal government should be encouraged to determine methods and locations for storage of high level wastes as soon as possible.

4. The present State policy of considering both the need and the proposed route for a given transmission line simultaneously has resulted in failure to consider these facilities until they are imminently needed. A preferable approach would be to identify and approve corridors needed for long term growth, with permission for construction granted at a later time, when short term need can be demonstrated. This would allow the selection of corridors which would be more acceptable from both environmental and developmental points of view. Incorporation of these corridors into county plans, on a basis similar to that used for identification of transportation corridors, would provide for orderly planning, and prevent land use conflicts.

CONVERSION TABLE

1 inch = 2.54 cm	1 acre = 4,047 m^2
1 foot = 0.305 m	1 lb = 0.454 kg
1 st. mile = 1,609 m	1 Btu = 252 calories

1 cu ft = 28.3 liter = 28.3×10^{-3} m^3

1 gallon = 0.134 cu ft = 3.785×10^{-3} m^3

1 cfs = 449 gpm = 28.3×10^{-3} m^3/sec

10^6 gpm = 2.233×10^3 cfs = 63 m^3/sec

1 acre foot = 4.36×10^6 cu ft = 123×10^3 m^3

Concentration:

1 ppb by weight in water = 1 g/m^3

$$1 \text{ ppm by volume in air} = \left(\frac{0.0224}{\text{gram mol. weight}}\right) \times \left(\text{concentration in } \mu g/m^3\right)$$

Gram molecular weight:

O_2 = 30; O_3 = 45; SO_2 = 62; NO = 29; NO_2 = 44;

The following values depend on many factors and vary a great deal.

Approximate values:

Heat value for coal = 12,500 Btu/lb

oil = 148,000 Btu/gallon

gas = 1,000 Btu/cu ft

One barrel of oil = 42 gallons

A coal burning plant operating at full capacity burns about 10 tons of coal per day per MW of capacity and requires about 900 gpm = 2 cfs = 0.057 m^3/sec of once through cooling water (heated by 10°F) per MW.

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CHAPTER I

POWER DEMANDS IN THE STATE OF MARYLAND

The operation and planning of electric utilities are determined by their customers' power demands. The last few years have witnessed important changes in patterns of demand which will have important implications for the construction of additional power plants. The most important of these changes is the sharp reduction in both actual and forecasted long-range load growth rates which has lead in recent years to cancellations, size reductions and scheduling delays for new generating units. In many cases it has also left utilities with substantial excess generating capacity -- a burden which is ultimately borne by ratepayers.

This chapter discusses the power demands facing utilities in the State of Maryland. The supply of electric power is covered in Chapter II. To place the subject of power demands in perspective, long term U.S. and Maryland energy usage trends are discussed. The structural interelationships among Maryland utilities are presented along with the basic characteristics of the service territories of the major systems. The future outlook for power demands on these systems is considered. A brief look at the Power Plant Siting Program (PPSP) load forecasting activities is included, although a more detailed discussion of the PPSP load forecasting methodology is deferred to Appendix A of this Report. Finally, this chapter provides a survey of the various methods and techniques which can be used to "manage" the growth of power demands. Although these methods are not being extensively employed in Maryland at the present time, they have the potential to significantly reduce the expensive oil-fired generation and the need to build additional capacity.

A. Historical and Projected National Trends in Energy Usage

Prices and supplies of competing sources of energy are determined by regional, national and even international markets. National policy decisions influence the operation of those markets, and as a consequence they shape energy options available in Maryland. It is helpful, therefore, to consider the national energy framework within which Maryland energy markets operate.

During the decades prior to the early 1970's energy production and usage grew steadily while energy prices remained stable and even declined somewhat. Energy demand was stimulated by rising living standards; increased automobile dependence arising from suburbanization; the tendency in industry to replace labor with energy-using capital equipment; the growth of energy intensive industries such as chemicals, paper and aluminum; and the increasing adoption of air conditioning. Stable prices in the face of rapid demand growth were made possible by several factors, including productivity advances and new fuel resource discoveries. Most important, however, were the rapidly growing imports of inexpensive oil, mainly from the Middle East.

These trends were brought to an abrupt end in 1973 by the Arab oil embargo and subsequent events. The embargo meant an immediate elimination of the key ingredient to stable energy prices -- cheap, abundant imported oil. Oil and gas (and even coal) prices skyrocketed, and availability, in some instances, became a problem. These developments, coupled with the severe 1974-1975 recession, brought about sharp declines in energy usage. Although economic growth resumed in 1976, energy prices had risen to such an extent that energy users were still in the process of adjusting to the earlier price shocks. Thus, by 1977 U.S. primary energy consumption was approximately at the same level as in 1973.

Another round of energy price shocks (and oil scarcity) occurred in 1979 accompanying the Iranian Revolution. These further price increases along with increasing national and state government efforts to encourage conservation led to a further dampening of demand.

The general energy trends of the late 1970's -- rising real prices, sluggish consumption growth and greater reliance upon coal -- are expected to continue in the future. According to the U.S. Department of Energy, Energy Information Administration (EIA), energy prices will increase faster than the rate of inflation, while overall U.S. (primary) energy consumption will only increase by 1.6 percent per year. Also, by 1995 coal is expected to dramatically increase its share of primary energy to 40.0 percent from 20.6 percent in 1980. These projections along with historical trends since 1960 are shown in Table I-1. The prices indicated in this table (expressed in 1972 dollars) are those received by U. S. producers. In 1980, the price per million Btu's (MBtu) was roughly $1.26 for coal, $4.88 for oil and $1.39 for natural gas.

Energy consumption by major end-use sector and fuel type is shown in Table I-2[1]. As these figures indicate, only the industrial sector is expected to increase its energy usage significantly. Electricity demand is projected to grow noticeably in all sectors, while oil consumption is projected to decline among all customer groups, even in transportation which is almost entirely powered by oil.

Both tables reveal some important trends in energy consumption. From 1960-1973, energy usage grew steadily while real prices declined. These trends were interrupted in the mid-1970's; total energy usage in 1980 only marginally exceeded that in 1973. Overall energy demand is projected by EIA to grow in the future but only modestly, and energy prices are expected to increase signficantly.

It is also important to recognize the shifts in fuel mix which have taken place and will continue to occur in the future. Up until the mid 1970's, oil and gas had been gradually and steadily displacing coal usage, particularly for transporation and building heating applications. Oil also began to replace coal in existing utility boilers as the result of State and Federal air pollution legislation and regulations, principally the Clean Air Act Amendments of 1970. Also, a large percentage of the new generating units brought on-line during this period was oil-fired. Trends in utility generation mix will be discussed in more detail in Chapter II.

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[1]The major difference between Table I-1 and I-2 is the "energy conversion" loss. Table 1-1 is primary energy while Table I-2 is end-use energy and is therefore net of conversions. This is most important in the electric utility industry where fuels are burned to generate electricity, and about two-thirds of the original energy is lost in the conversion process. Thus, the 1995 total energy usage in Table I-2 is 65.7 quads compared to 93.5 quads of primary energy. Nearly a third of primary energy is lost in the conversion process and most of that is in the electric utility sector. This furthur emphasizes the prominent role of that industry in the energy sector.

Table I-1

U.S. Energy Consumption and Price by Primary Energy Type 1960-1995

Year	Coal		Petroleum		Natural Gas		Nuclear	Hydroelectric	Total
	Quads	Price	Quads	Price	Quads	Price	Quads	Quads	Quads
1960	10.1	$0.40	20.0	$0.83	12.7	0.21	0.1	1.6	44.5
1965	11.9	0.34	23.2	0.76	16.1	0.21	0.1	2.0	53.3
1970	12.7	0.35	29.5	0.68	22.0	0.19	0.2	2.6	67.1
1973	13.3	0.38	34.9	0.71	22.5	0.21	0.9	3.0	74.6
1974	12.9	0.60	33.5	1.43	21.7	0.27	1.2	3.3	72.6
1975	12.8	0.62	32.7	1.50	19.9	0.35	1.8	3.2	70.6
1976	13.7	0.62	35.1	1.50	20.3	0.43	2.0	3.0	74.4
1977	14.1	0.64	37.0	1.56	19.6	0.55	2.7	2.4	75.8
1978	13.9	0.70	38.0	1.51	20.0	0.59	3.0	3.2	78.1
1979	15.1	0.71	37.1	1.98	20.7	0.71	2.8	3.2	78.9
1980	15.7	0.74	34.3	2.87	20.4	0.82	2.7	3.1	76.2
1985	20.6	0.90	30.3	4.13	18.1	1.96	5.6	3.2	77.8
1990	27.6	0.94	30.7	4.58	17.4	2.06	8.0	3.2	86.9
1995	35.0	1.00	29.1	5.58	17.0	2.51	9.1	3.3	93.5

Table 1-1 (Continued)

Annual Rates of Growth (%)

	Coal		Petroleum		Natural Gas		Nuclear	Hydroelectric	Total
	Quads	Price	Quads	Price	Quads	Price	Quads	Quads	Quads
1960-1973	2.1%	-0.5%	4.4%	-1.1%	4.5%	0.0%		5.0%	4.1%
1973-1980	2.4	10.1	-0.3	22.0	-1.4	22.4	17.0	0.5	0.3
1980-1985	5.6	4.4	-2.5	7.5	-2.4	19.0	15.7	0.6	0.4
1980-1995	5.5	2.0	-1.1	4.5	-1.2	7.7	8.4	0.4	1.4

Notes : (a) Quad = Quadrillion Btu's = 10^{15} Btu.
(b) Prices are deflated to 1972 dollars by the GNP Deflator. Prices are expressed in dollar per million Btu.
(c) Coal prices are bituminous delivered prices to electric utilities. Petroleum prices are refiner aquisition prices, and projections are world oil prices. Gas prices are domestic well head prices.
(d) All projections are the EIA "mid" case projections.

Source: (1), (2)

Table I-2

Energy Consumption by End-Use and Fuel Type
(Quadrillion Btu's)

	1965	1973	1978	1985[a]	1995[a]
Residential[b]					
Oil	3.1	3.8	3.4	2.6	1.9
Gas	4.2	5.2	5.2	5.0	5.1
Electricity	1.0	2.0	2.4	2.8	3.5
Total**	8.6	11.2	11.1	10.6	10.6
Commercial[b]					
Oil	2.0	2.4	2.3	1.4	1.0
Gas	1.4	2.4	2.4	2.3	2.8
Electricity	0.8	1.5	1.7	2.0	2.7
Total (c)	5.4	7.7	7.7	7.1	8.1
Transportation					
Total	12.8	18.9	20.9	18.3	18.7
Industrial					
Oil	3.7	5.2	6.5	3.5	4.0
Gas	7.3	10.4	8.5	8.6	9.3
Coal	5.4	4.4	3.4	4.7	7.3
Electricity	1.5	2.3	2.7	3.4	5.1
Total (c)	19.1	24.0	23.2	22.5	28.3

(a) Forecasts are EIA mid-price case.

(b) Master metered apartments are here listed as residential.

(c) Total includes all energy sources, not merely those listed in the table.

Source: (2)

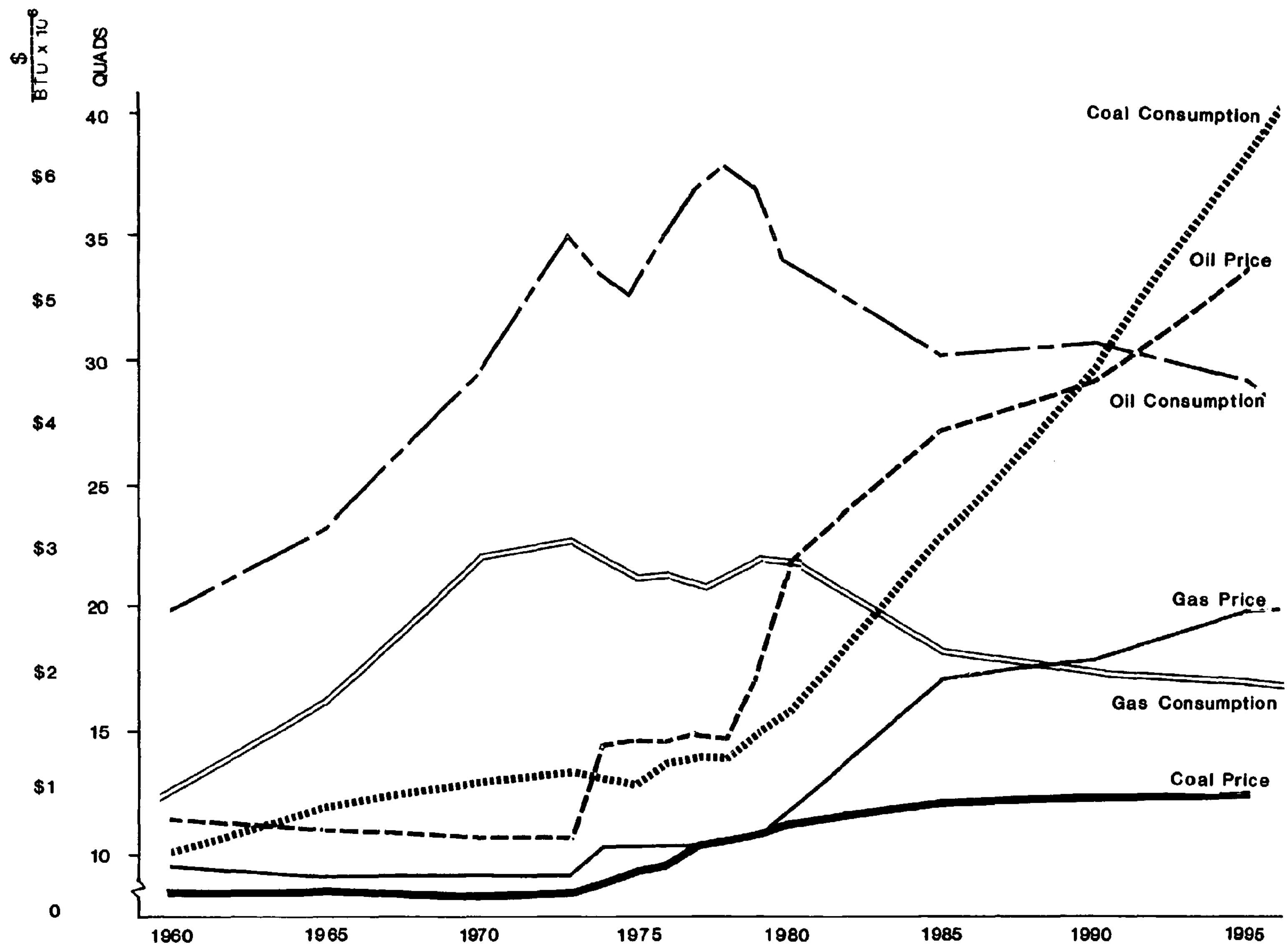

Figure I-1. U.S. primary energy consumption and prices in 1972 dollars. Prices quoted in text are in 1980 dollars.

With the dramatic increases in gas and oil prices relative to coal, and the perception of gas and oil as insecure, industry and utilities began switching toward coal. At the same time the household and transportation sectors have been increasing their efforts to conserve on oil and gas usage. With natural gas in short supply in the early and mid 1970's, federal and state authorities implemented curtailment plans. Many industrial users were curtailed, and in many areas of the country (including Maryland) restrictions on new residential and commercial hook-ups were imposed. As a result, the natural gas share of total energy usage fell sharply within the space of just a few years.

During the decade of the 1970's, coal's decline was arrested and even moderately reversed. Over the next 15 years EIA expects an enormous relative and absolute increase in coal usage as both industrial and utiiity boilers shift away from oil and gas. Since most coal (over 70 percent) is consumed by the electric utility industry, and since coal is already the most important fuel in that industry, electricity demand growth will help to drive this process.

EIA projects that electricity demand will grow by roughly three percent per year while the end-use demand for other energy forms will stagnate. Industrial usage of coal will increase, but that will be more than offset by reductions in oil and gas, mainly in the nonindustrial sectors. Electricity will therefore become more and more heavily relied upon to serve this nation's future energy needs. The increasing relative importance of electricity is also largely responsible for the growth of coal's share of total primary energy.

Historical and projected electrical energy demand are shown in Table I-3. Electricity sales, particularly to residential and commercial customers, grew rapidly prior to 1973. Since 1973 sales growth has been moderate. EIA projects that a change in growth patterns will occur over the next 15 years. Whereas in the past there has been a fairly clear tendency for the residential and commercial demands to grow more rapidly than industrial, in the future the industrial sector is expected to grow more rapidly. The projected industrial growth rate of 4.2 percent annually is nearly double the combined residential/commercial rate of 2.3 percent.

B. Energy Usage in Maryland

Comparisons of historical energy usage patterns between the U.S. and Maryland through 1977 are presented in Tables I-4 and I-5. These tables present energy consumption at the end-use level by major customer groups and major fuels. It does not include energy consumed in the process of producing electricity. In addition to percentage breakdowns for the various fuel-types and end-use groups, Table I-5 shows consumption growth rates for 1960-1973, 1973-1977 and 1960-1977.

Although similar in many respects, there are some noticeable differences between Maryland and the U.S. in patterns of energy usage. In Maryland, the residential, commercial and transportation sectors are relatively more prominent energy users, whereas the industrial sector is substantially less energy intensive than nationwide. Natural gas is relatively less important in Maryland (15.9 percent of total energy consumption compared to 26.7 percent nationwide in 1977), but petroleum is noticeably more important. Nearly 60 percent of all energy consumed in Maryland at the end-use level is petroleum compared to

Table I-3

Sales of Electricty by Customer Class in the U.S
(Billions of kWh)

Year	Residential	Commercial	Industrial	Other	Total
1960	202	131	325	32	689
1970	466	307	571	48	1,392
1973	579	388	686	59	1,713
1974	578	385	685	58	1,706
1975	585	402	675	68	1,730
1976	603	424	740	70	1,836
1977	641	445	772	70	1,929
1978	671	460	801	73	2,005
1979	683	473	842	73	2,071
1980	717	488	815	74	2,094
1985	784	524	1,002	--	2,418
1990	881	612	1,231	--	2,831
1995	989	713	1,504	--	3,332
			Annual Rates of Growth		
1960-1973	8.4%	8.7%	5.9%	4.8%	7.3%
1973-1980	3.1	3.3	2.5	3.3	2.9
1980-1995	2.2	2.6	4.2	---	3.2

Source: (1), (2)

Table I-4

U.S. and Maryland Energy Consumption, 1960-1977
(Trillion Btu's) (a)

	1960		1973		1977	
Residential (b)	US	MD	US	MD	US	MD
Petroleum	2,638	52.7	3,195	57.9	2,990	56.4
Gas	3,202	47.4	5,036	75.4	4,983	67.3
Electricity	670	9.3	1,890	32.4	2,226	36.7
Total (c)	7,183	117.1	10,303	166.4	10,283	160.7
Commercial (b)						
Petroleum	2,497	61.9	3,739	90.6	3,515	72.4
Gas	1,053	8.3	2,680	30.8	2,577	28.9
Electricity	468	4.0	1,561	25.0	1,832	26.1
Total (c)	4,398	78.8	8,083	147.0	7,973	127.6
Industrial						
Petroleum	2,319	59.2	3,184	73.8	3,694	49.8
Coal	4,685	140.0	4,270	160.7	3,823	84.6
Gas	4,481	17.2	10,567	62.7	8,740	39.1
Electric	1,176	16.5	2,345	37.6	2,583	44.1
Total (c)	15,386	257.2	24,679	365.0	23,216	243.3
Transport						
Total (c)	9,639	163.6	18,311	302.7	19,515	318.3
Totals						
Petroleum	17,093	337.4	28,429	525.0	29,714	496.9
Gas	8,736	72.9	18,283	168.9	16,300	135.3
Electricity	2,331	29.8	5,811	95.0	6,656	106.9
Coal	5,738	152.3	4,555	162.3	3,957	85.2
Grand Total (c)	36,606	616.7	61,376	981.1	60,987	849.9

(a) Excludes energy used to produce electricity.

(b) Master metered apartments are here listed as commercial.

(c) Totals include all sources of energy production and consumption and not only those listed.

Source: (3)

Table I-5

U.S. and Maryland Energy Consumption, 1960-1977

	Fuel Type and End-Use Sector Shares (1977)		% Annual Consumption Growth Rates					
			1960-1973		1973-1977		1960-1977	
	U.S	MD.	U.S.	MD.	U.S.	MD.	U.S.	MD.
Residential								
Petroleum	29.1%	35.1%	1.5%	0.7%	-1.6%	-0.7%	0.8%	0.4%
Gas	48.5	41.9	3.5	3.6	-0.3	-2.8	2.6	2.1
Electricity	21.7	22.8	8.3	10.1	4.2	3.2	7.3	8.4
Commercial								
Petroleum	44.1	56.7	3.2	3.0	-1.5	-5.5	2.0	0.9
Gas	32.3	22.7	7.5	10.6	-1.0	-1.6	5.4	7.6
Electricity	23.0	20.5	9.7	15.1	4.1	1.1	8.4	11.7
Industrial								
Petroleum	15.9	20.5	2.5	1.7	3.8	-9.4	2.8	-1.0
Gas	37.7	16.1	6.8	10.5	-4.5	-11.1	4.0	5.0
Electricity	11.1	18.1	5.5	6.5	2.5	4.1	4.7	6.0
Coal	16.5	34.8	-0.7	1.1	-2.7	-14.8	-1.2	-2.9
Fuel Shares								
Petroleum	48.7	58.5	4.0	3.5	1.1	-1.4	3.3	2.3
Gas	26.7	15.9	5.9	6.7	-2.8	-5.4	3.7	3.7
Electricity	10.9	12.6	7.3	9.3	3.5	3.0	6.4	7.8
Coal	6.5	10.0	-1.8	0.5	-3.5	-14.9	-2.2	-3.4
End-Use Shares								
Residential	16.9	18.9	2.8	2.7	-0.1	-0.9	2.1	1.9
Commercial	13.1	15.0	4.8	4.9	-0.3	-3.5	3.6	2.9
Industrial	38.1	28.6	3.7	2.7	-1.5	-9.6	2.5	-0.3
Transportation	32.0	37.5	5.1	4.9	1.6	1.3	4.2	4.0

Source: Table I-4

approximately 50 percent for the entire U.S. Maryland's relatively heavy oil dependence is characteristic of most of the Northeast part of the country.

Energy usage grew rapidly in Maryland (as in the rest of the nation) between 1960 and 1973 for all major fuels (except coal at end-use). The decline in coal consumption (excluding its use in generating electricity) was more than offset by large increases in the consumption of gas, oil and electricity. Electricity demand more than tripled in Maryland during this period. Since 1973 energy demand has fallen sharply, more sharply than for the nation as a whole. An important exception to this trend is electricity usage which grew by 3 percent per year. However, even this growth is very modest compared to the pre-1973 annual growth rate of over 9 percent. This post-1973 conservation has occurred, both in Maryland and the rest of the nation, in all major end-use classes except transportation. The exceptionally sharp reduction in energy consumption by Maryland industry has been due to both conservation efforts and a longer term tendency for economic activity in the heavy industry (i.e., energy intensive) sectors in the State to decline.

C. The Electric Utility Industry in Maryland

Households and business in the State of Maryland receive electric power from four large and several small utilities operating in the State. Generally speaking, these utilities fall into three main categories:

(a) Investor owned utilities -- Typically, these are large, integrated electric systems engaged in the production, transmission and sale of electricity. Such systems often operate in more than one regulatory jurisdiction and may sell power on a firm basis to smaller power distributors.[1] Most Maryland customers are served by one of four such systems.

(b) Municipal utilities -- Several medium-size and small towns in the State own and operate their own utility systems. In most instances Maryland municipals have operated as distribution systems only, purchasing bulk power from the investor-owned utilities.

(c) Rural Electric Cooperatives -- Coops are similar in many respects to municipal utilities in that they are not set up as profit making ventures. Just as municipals are "owned" by the voters, coops are operated by the ratepayers with financial assistance from the Federal government's Rural Electrification Administration. Coops serve predominantly rural areas, although they often also serve the towns within their geographic service areas. Two major rural electric cooperatives operate in Maryland.[2]

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1 Two investor owned utilities in Maryland, the Susquehanna Power Company (a subsidiary of Philadelphia Electric) and Pennsylvania Electric Company have hydroelectric facilities in Maryland at Conowingo Dam and Deep Creek Lake, respectively. Neither utility sells power on a retail basis in Maryland. Conowingo Power Company (also a Philadelphia Electric subsidiary) serves most of Cecil County but has no generating capacity of its own.

2 In addition, A&N and Somerset Rural Electric Cooperatives serve a very small number of customers on Smith Island and in Garrett County, respectively.

With the resurgence of interest in cogeneration (discussed in Chapter II) and small power production, many large power users (and perhaps even some households) may satisfy some or all of their requirements by producing their own power. Currently, the Sparrows Point Bethlehem Steel plant produces much of the electricity it consumes.

Four major investor-owned utilities serve the majority of the customers in the State and produce nearly all of the electricity consumed. These utilities are:

- Baltimore Gas & Electric Company (BG&E). -- BG&E serves nearly 750,000 customers in the Baltimore metropolitan area. In 1980 BG&E's annual peak was 3,969 megawatts compared to installed generating capacity of 4,995 at the time of the peak. Unlike the other large utilities in the State, BG&E has no service territory outside of Maryland nor does it provide power to any municipals or cooperatives.

- Delmarva Power & Light Company (DP&L). -- DP&L, directly or indirectly, provides almost all of the power consumed on the Delmarva Peninsula (and thus the Eastern Shore of Maryland) with the exceptions of Cecil County, the City of Dover and the Town of Easton. DP&L serves nearly three-quarters of the Peninsula electric customers at retail, and it provides bulk power as a wholesaler to the numerous municipals and coops which directly serve the rest. In 1980 DP&L experienced a systemwide peak demand of 1,581 megawatts and a Maryland portion peak of 410 megawatts.[1] At the time of the peak the Company owned 2,062 megawatts of generating capacity systemwide with only 252 megawatts located in Maryland. Thus, the bulk of the customers, load and service territory is located in Delaware.

- Potomac Electric Power Company (Pepco). -- Pepco serves approximately 500,000 customers at retail in the District of Columbia and its Maryland suburbs. In addition, it indirectly serves most of St. Mary's, Calvert and Charles Counties through its wholesale sales to the Southern Maryland Electric Cooperative (SMECO). It also serves a small number of customers in the Northern Virginia suburbs. Maryland sales comprise slightly more than half the entire Pepco system. In 1980 Pepco experienced a peak demand of 4,142 megawatts compared to an installed generating capacity of 4,999 megawatts.

- Potomac Edison Company (PE). -- PE provides power to Western Maryland along with contiguous areas in Virginia and West Virginia. PE is one of the three utility subsidiaries of the Allegheny Power System (APS). The other two, Monongahela and West Penn Power, serve the northern half of West Virginia and southwestern Pennsylvania, respectively. APS experienced a peak of 5,564 megawatts for the winter of 1980/1981 (both APS and PE are winter peaking) while having 7,671 megawatts of generating capacity. The Maryland portion of PE comprises approximately a fifth of the APS load, but only 117 megawatts of generating capacity are located in the State. In addition to serving retail customers in the western counties, PE sells power on a wholesale basis to three Maryland municipals.

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[1] These peak demand figures include the loads of all municipals and cooperatives with the exception of Easton, Maryland and Dover, Delaware.

Table I-6 presents the municipals and cooperatives operating in Maryland along with some basic descriptive data. In terms of sales, most of the municipals are quite small, and only Easton has been generating any significant amount of power.[1] It is also interesting to note that, in contrast to many investor-owned utilities, the majority of sales by municipals and cooperatives are made to residential customers. The residential sales figure of 1,020 million MWh represents 57 percent of total retail electricity sales of these companies. It should be noted that although Easton Utilities is not a wholesale customer, it is fully integrated with DP&L and engages in economy sales (and purchases) on an interchange basis. It is the only municipal or cooperative in the State which is not a wholesale customer of another utility.

Figure I-2 is a map of the State of Maryland identifying the areas of the State served by each utility. The DP&L service area is difficult to identify on the map since the Maryland Eastern Shore is also served by Choptank and the several municipals. The municipals are identified by numbered dots (except for Centreville). In the central portion of the Eastern Shore, most of the rural portions are served by Choptank while DP&L serves the towns.

Three of the four major utilities in Maryland are part of larger multistate, and in one case, multicompany systems. These four systems not only provide retail service to most of the State, they also provide nearly all of the bulk power to the municipal and cooperative power distributors. These systems do not function as totally isolated entities, however. There are many ways in which a utility can interact with other systems even if those other systems operate in other regulatory jurisdictions. Such arrangements may include integrated power pooling, joint ownership of generation or transmission facilities, sales of firm power, opportunistic economy sales and diversity power swapping arrangements. Maryland utilities routinely engage in bulk power transactions primarily through the Pennsylvania-New Jersey-Maryland Interconnection (PJM). With the exception of Potomac Edison (and the municipals it serves), all Maryland electric utilities are fully integrated with the PJM power pool. As a subsidiary, Potomac Edison participates fully in the APS power pooling arrangements. In addition, PJM and APS themselves conduct transactions with other utilities and power pools. For example, APS and The Virginia Electric Power Company (Vepco) engage in a diversity exchange whereby Vepco (a summer peaking utility) sends power to APS in the winter, and APS (a winter peaking utility) returns those kilowatt hours during the summer months.

To illustrate the importance of the off-system transactions, Table I-7 shows the quantity energy purchased and sold to other systems along with total power supplied to meet native load (i.e., retail and wholesale obligations). For purposes of comparison, power purchased is expressed as a percentage of total power supply, and power sold (off-system) is expressed as a percentage of system generation. As the figures indicate, Potomac Edison is a large net purchaser of power, but the three Maryland PJM utilities are net sellers to the pool.

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[1] Choptank, through its parent organization, The Old Dominion Electric Cooperative, intends to share in 50 megawatts from the Vienna 9 coal-fired unit which has a planned in-service date of 1990.

Table I-6

Maryland Municipal and Rural Electric Cooperatives (1980)

	Sales (MWh)			Power Source	Generation (MWh)	Peak Demand (MW)	Generating Capacity (MW)
	Residential	Nonresidential	Total				
Municipals							
Berlin	7,369	15,971	23,340	DP&L	6,203	6.4	3.5
Centreville*	22,093	16,408	38,501	DP&L	0	8.8	0.0
Easton	34,659	72,054	106,713	Self & DP&L	93,400	23.6	47.8
Hagerstown	81,412	123,164	204,576	PE	0	48.9	20.0
St. Michaels*	20,395	13,084	33,479	DP&L	0	10.8	0
Thurmont	5,611	25,001	30,612	PE	0	6.8	0
Williamsport	6,053	5,775	11,828	PE	0	3.1	0
Cooperatives							
SMECO	616,788	415,947	1,032,735	Pepco	0	269.1	0
Choptank	225,406	70,905	296,311	DP&L	0	69.8	0
Total	1,019,786	758,309	1,778,095		99,603	447.3	71.3

* Centreville and St. Michaels are no longer independent municipal systems. They are now served at retail by DP&L.

Source: (4)

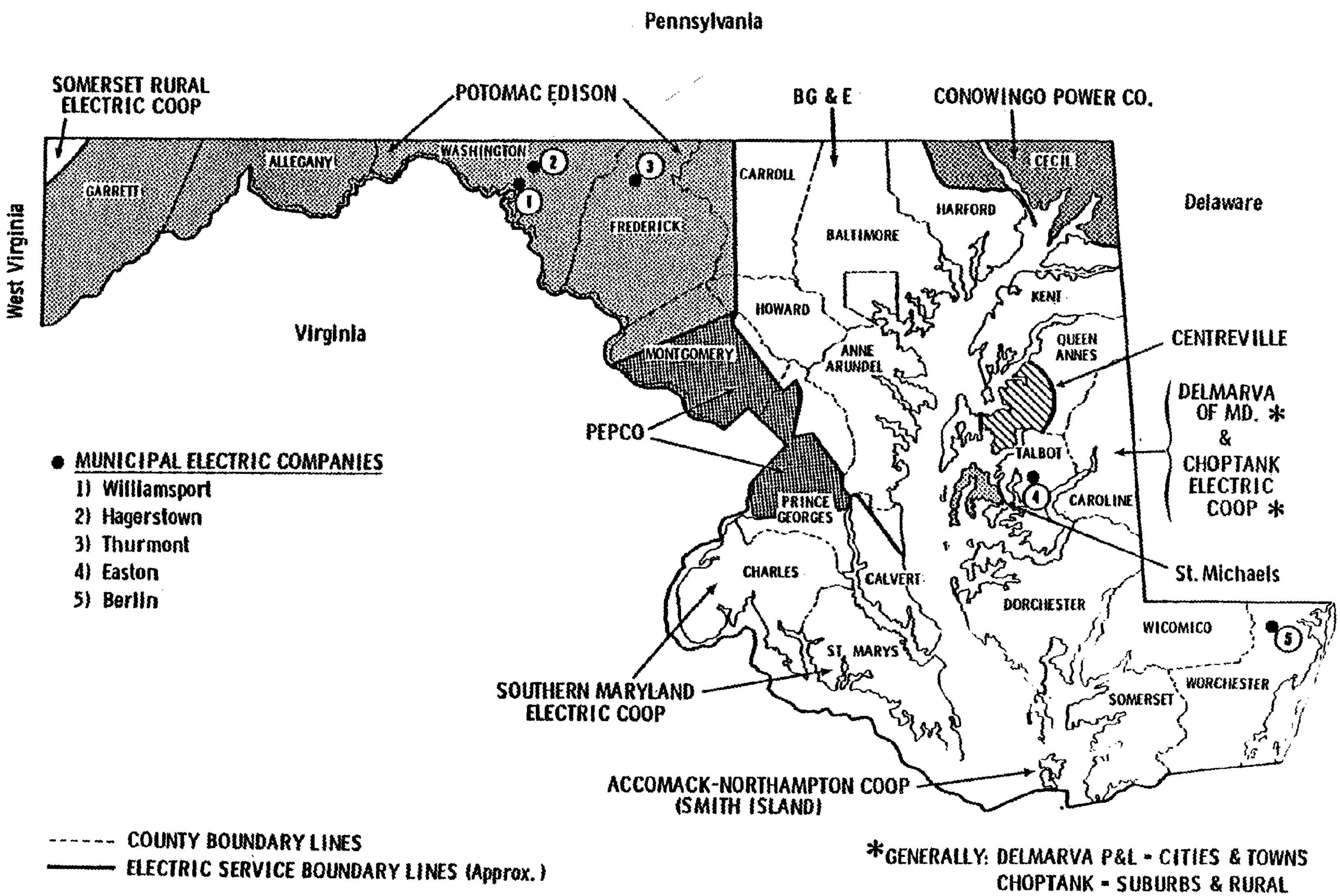

Figure I-2. Service territories of Maryland electric utilities

Table I-7

Interchange Purchases and Sales, 1980
(Millions kWh)

	Purchases(a)		Sales (b)		Net	Total Power
	Quantity	%	Quantity	%	Purchases	Supply
Pepco	4,832	27.4%	5,265	29.1%	-433	17,647
BG&E	1,665	9.0	3,013	15.1	-1,347	18,573
DP&L	696	8.7	1,059	12.6	-363	8,029
P.E.	2,681	25.5	1,590	16.9	1,091	10,499
Total	9,874	18.0	10,927	19.6	-1,052	54,748

(a) Purchases as a percentage of total power supply.

(b) Off-system sales as a percentage of system generation.

Source: (5)

Of these three, BG&E is by far the largest net seller, both on an absolute and relative basis. For all four major Maryland utilities, power pool purchases and sales are a large percentage of system capability. Thus, off-system transactions constitutes a very important aspect of the operations of all major Maryland utilities.

The structure of the electric utility industry in Maryland is summarized in Figure I-3. The heavy, vertical lines (without arrows) indicate a corporate relationship; for example, Potomac Edison is a subsidiary of APS. Unidirectional arrows indicate power flows, generally sales for resale; while the bidirectional arrows indicate interchange sales.

D. Service Areas of the Major Maryland Electric Utilities

As discussed in the previous section, nearly all of Maryland is served, either directly or indirectly, by four major, integrated utilities -- BG&E, Pepco, DP&L and PE. With the exception of BG&E, each of these utilities possesses a very substantial amount of service territory outside of the State. In this section we shall examine the service areas of each utility, both the past development patterns and the future outlook. In particular, we shall examine the factors influencing the demand for electricity in each service area.

Baltimore Gas & Electric Company

BG&E serves a population of approximately 2.4 million people in a 2,300 square mile area. This area includes Baltimore City and eight surrounding counties. In addition to the City, the area contains most or all of Baltimore, Anne Arundel, Harford, Carroll and Howard Counties and very small portions of Calvert, Montgomery and Prince Georges Counties. Thus, the service area roughly corresponds to the Census Bureau's definition of the Baltimore Standard Metropolitan Statistical Area.

The economy of this region is diverse. Baltimore City and County contain considerable heavy and light manufacturing activity, and with one of the East Coast's largest international ports Baltimore is also a major commercial center.

The Baltimore area economy has been substantially dependent on its heavy manufacturing base but will probably be less so in the future. Manufacturing activity is not expected to grow rapidly; and the impetus for growth is instead expected come from the commercial sector. In 1970 manufacturing accounted for 22 percent of Baltimore region employment, but this percentage has fallen significantly over the past decade. The Maryland Department of State Planning projects that by 1990 manufacturing will comprise only 14 percent of total employment, while the service sector and government will experience large gains.

Electricity demand has reflected the changing economic conditions facing businesses and households. Prior to the mid-1970's electricity consumption grew rapidly in response to rapid growth in the economy and favorable electricity rates. Since then, economic growth has slowed considerably while electricity prices increased dramatically. As shown below, electricity demand growth slowed noticeably for each major customer class and for peak demand. The most dramatic change has been a decline in peak demand growth from 9.1 percent per year to 2.5 percent. The system load factor decreased from 1966 to 1973 and has remained fairly constant since then.

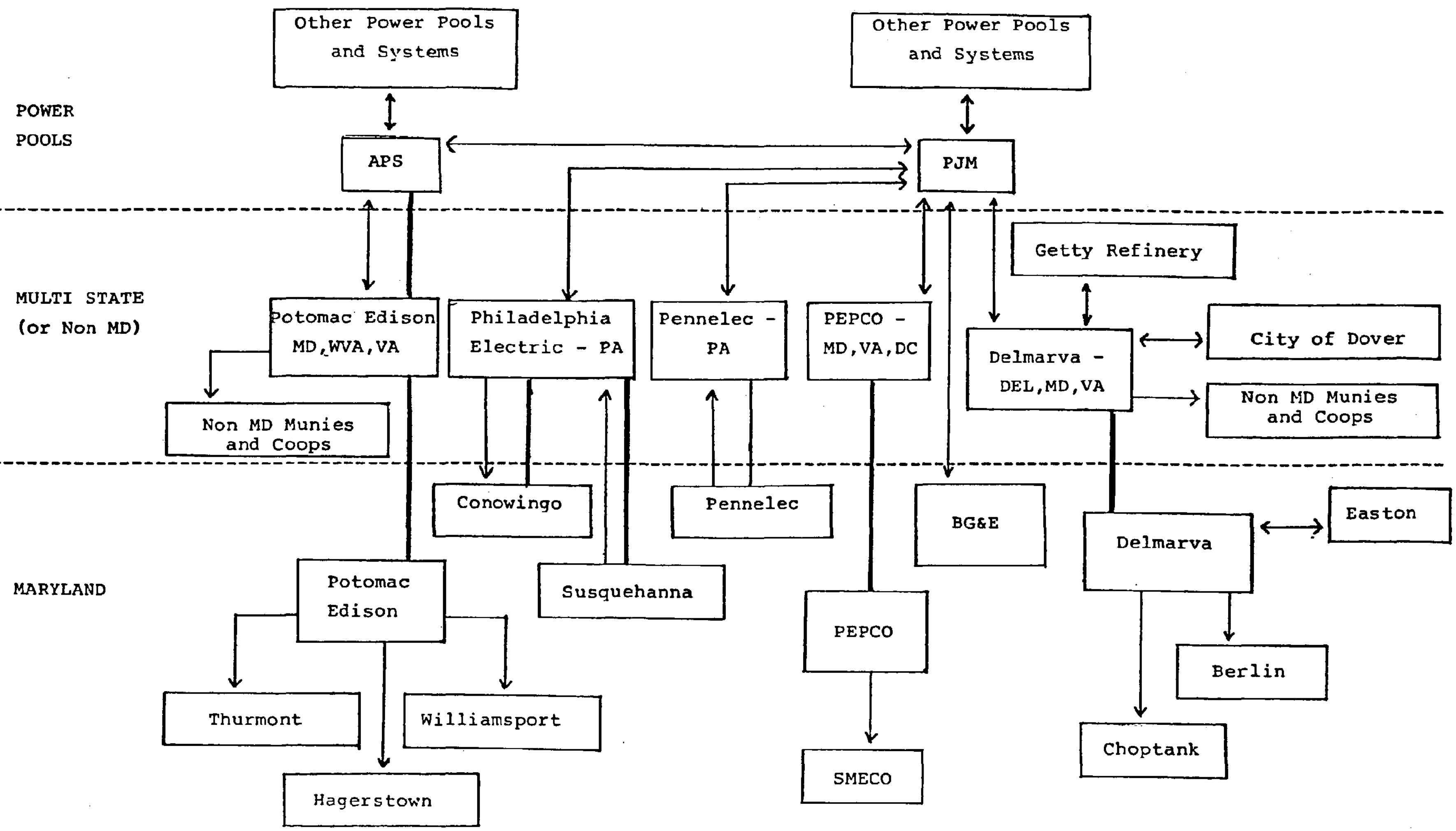

Figure I-3
Schematic diagram of the electric utility industry in Maryland

Table I-8

Growth in Energy and Peak Demand on the BG&E System
(thousands of MWh)

	1966	1973	1980	Annual Growth Rates 1966-1973	1973-1980
Residential	2,347	4,618	6,005	10.2%	3.8%
Commercial	1,771	2,582	2,933	5.5	1.8
Industrial	4,365	6,845	7,962	6.6	2.2
Total	8,653	14,341	17,228	7.5	2.7
Peak Demand (MW)	1,817	3,334	3,969	9.1	2.5
Load Factor	58.9%	52.7%	53.0%		

Important economic and demographic shifts have taken place within the Baltimore region. The economies of Baltimore City and County, the two largest entities in the area served by BG&E, have been stagnant relative to the rest of the area. Over the past decade and a half the City has experienced a significant net loss of both employment and population. At the same time the newer, rapidly suburbanizing areas, particularly Anne Arundel and Howard Counties, are growing rapidly. To some extent these geographic trends mirror the sector trends. Heavy manufacturing, primarily located in Baltimore City and County, has been gradually declining in comparison to commercial activity and light manufacturing (and government).

These trends are expected to continue though not to the same extent as in the past. For example, the latest Maryland Department of State Planning projections expect that Baltimore City's population will continue to decline though at a slower rate than in the past (6). Howard and Anne Arundel Counties are expected to continue to grow considerably more rapidly than the rest of the State but also at a slower rate than in the past. These trends toward a declining heavy manufacturing sector and increased suburbanization make it unlikely that BG&E's rather low load factor will improve significantly over time.

Potomac Electric Power Company

Pepco serves a population of roughly two million persons in a 643 square mile area. This service area includes the entire District of Columbia, most of the Maryland suburban counties of Prince Georges and Montgomery, and a small section of Arlington County, Virginia. In addition, Pepco supplies all of the bulk power requirements of the Southern Maryland Electric Cooperative which serves all of Charles and St. Mary's Counties and most of Calvert County.

The three principal regions which directly or indirectly comprise Pepco's service area have widely divergent characteristics. The District is a highly urbanized environment of government and commercial office buildings and large apartment complexes. The suburban Maryland region is a more affluent largely residential area, but with a large retail trade sector. The Southern Maryland region, which is served only indirectly by Pepco, is largely rural and small town though with some suburban development.

The distinguishing aspect of the Pepco area economy is the virtual absence of any significant manufacturing activity. In fact, Pepco is the only large utility in the nation without a large industrial load. That fact, along with the predominance of air conditioning in the Washington area, accounts for the relatively low system load factor which Pepco has experienced over the years.[1] The main "industry" in the area served by Pepco is the Federal government. Thus, the lack of a manufacturing base coupled with the Federal presence tends to insulate Pepco sales from the effects of the business cycle. Whereas the nationwide unemployment rate in 1980 was 7.1 percent, the Washington area averaged only 4.2 percent.

Table I-9 indicates the employment patterns within the Washington Metropolitan Area for selected years. These figures should be viewed cautiously since the geographic coverage of these data includes certain areas outside of the Pepco service area (e.g., Northern Virginia), and it excludes Southern Maryland. It nevertheless serves as a useful guide.

Over the past decade and a half major employment gains have taken place, but the sectoral shares have been remarkably stable. The only noticeable change has been a tendency in recent years for the service/finance sector to displace government employment. That tendency is, however, not dramatic and has little effect on energy demand. Manufacturing, which occupies roughly twenty percent of employment nationwide, accounts for less than four percent of Washington area jobs. Moreover, even this small amount tends to be in such activities as printing which use little energy. The combination of government and services/finance dominate employment in the Washington area comprising nearly 70 percent of the total.

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[1] In 1980 the Pepco system annual load factor was only 48.6 percent.

Table I-9

Employment by Sector Washington, D.C. Area
(Thousands)

Sector	1980* Number	1980* Percent	1973* Number	1973* Percent
Manufacturing	56.0	3.6%	45.2	3.6%
Construction	75.4	4.8	77.9	6.2
Transportation/ Utilities	67.5	4.3	61.6	4.9
Trade	296.2	18.9	247.1	19.7
Services/Finance	512.2	32.7	348.9	27.7
Government	560.5	35.8	477.1	37.9
Total	1,567.8	100.0	1,257.8	100.0

* Figures are for April of indicated year.

Source: (7).

Table I-10 demonstrates the extent to which power demand growth rates on the Pepco system have fallen since 1973. Prior to that year, sales were growing by more than eight percent per year, and have since slowed to slightly over two percent per year. Peak demand growth has fallen even more dramatically, revealing a slight tendency for Pepco's very low annual load factor to improve over time. The pattern of growth in the residential and general service class is similar. Sales to SMECO continue to grow fairly rapidly as the Southern Maryland region continues to undergo a gradual suburbanization process.

Table I-10

Growth in Energy and Peak Demand on the Pepco System
(Thousands of MWh)

	1966	1973	1980	Annual Growth Rates 1966-1973	1973-1980
Residential	1,978	3,529	4,026	8.6%	1.9%
Nonresidential	5,661	9,704	11,425	8.0	2.4
Sales to SMECO	330	755	1,106	12.6	5.6
Total	7,969	13,988	16,557	8.4	2.4
Peak Demand (MW)	2,123	3,680	4,142	8.2	1.7

There are several identifiable factors accounting for the decline in demand growth. Although some economic development in the Washington area has occurred in recent years, it has done so at slower rate than in the past. Population growth, in particular, has slowed considerably. Moreover, much of the Washington area development which has occurred in recent years has been outside of the Pepco service area -- i.e., in Northern Virginia and the extremeties of Prince Georges and Montgomery Counties. The District's population, which is entirely served by Pepco, has been declining in absolute terms. Also, it has been hypothesized that Pepco residential and commercial customers have already achieved a very high level of air conditioning saturation (which represents a large percentage of the Company's load), and the growth opportunities from further saturation may be modest. Finally, it is likely that the combined effects of higher prices and conservation programs also have substantially contributed to this demand growth rate reduction.

Delmarva Power & Light Company

DP&L serves directly or indirectly the Delmarva Peninsula -- a geographic region which includes the entire State of Delaware, the Maryland Eastern Shore and two Virginia counties. This region contains about 5,700 square miles and a population of 860,000. Electric service is also furnished to households and businesses on the Peninsula by one other, very much smaller, privately owned utility (Lincoln & Ellendale); by eleven municipal electric utility systems;[1] and by three rural electric cooperatives. DP&L itself serves directly almost 80 percent of the retail electric load on the Peninsula; and it generates more than 90 percent of the bulk power consumed. DP&L has a larger role in generation than in retail sales, because it provides indirect service to much of the load served by the other distribution utilities. Dover, Delaware and Easton, Maryland are the only other systems generating significant quantities of power, and they buy (and sell) power on an interchange basis with DP&L. Thus, all utilities operating on the Peninsula are fully integrated with DP&L.

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[1] Until recently the Maryland towns of St. Michaels and Centreville operated their own municipal electric systems. Currently, those two towns are now served at retail by DP&L.

Some energy is also generated by industrial companies for their own use. Dupont's Seaford nylon plant generates most of the power it consumes and purchases back-up power from DP&L. A small amount of energy from the Getty Oil Company's joint steam-electricity facility is produced in excess of refinery requirements and is sold to DP&L.

Except for a major manufacturing and urban center in and around Wilmington, the Delmarva Peninsula is a largely rural region. An important food processing industry has developed in recent years as a natural complement to the region's agricultural activity. In addition, there are several popular ocean and Bay resorts, the largest being Ocean City, Maryland. Maryland comprises only about a quarter of DP&L's total load, and virtually all of the heavy manufacturing on the Peninsula is in Delaware. The Virginia service territory is very small and accounts for less than five percent of total Peninsula power demands.

The economy of the Peninsula, as well as the differences among the three states there, can best be understood by examining employment patterns as shown below for the year 1977. U.S. breakdowns are included on this table as a benchmark.

Table I-11

Employment Shares by Major Sector
on the Delmarva Peninsula, 1977

	Delaware	Maryland	Virginia	Total Peninsula	U.S.
Agriculture	2.3%	10.6%	12.0%	4.9%	3.6%
Manufacturing	26.2	21.5	26.8	25.1	21.7
Trade	19.4	21.4	13.4	19.6	20.4
Government	18.7	15.9	19.7	18.0	16.7
Other	33.4	30.6	28.1	32.4	37.6

Source: Bureau of Economic Analysis unpublished data.

This table suggests that the structure of the Delmarva economy is similar to the rest of the nation. However, these sector definitions are extremely broad and tend to hide important differences among the various portions of the Peninsula. For example the most important manufacturing industry in the Maryland service area is food processing, an activity which does not use large quantities of energy. By contrast, chemicals, an extremely energy intensive industry, dominates manufacturing in Delaware. Thus, within these employment categories are major differences in economic activity which are themselves expressed in electricity demand. This is shown below in Table I-12.

Table I-12

Customer Class Shares of Electricity Demand
On the Delmarva Peninsula, 1977

	Delaware	Maryland	Virginia	Total Peninsula	U.S.
Total Sales (thousands of megawatt-hours)					
	5,293	1,794	271	7,358	1,929,000
Percentage Distribution by Economic Sector					
Residential	30.3%	50.0%	47.1%	36.0%	33.2%
Commercial	29.5	32.8	41.5	30.8	23.1
Industrial	39.6	15.9	10.7	32.4	40.0
Other	0.6	1.3	0.7	0.8	3.7

The obvious, dramatic differences are in the industrial energy sales category. Delaware is typical of the U.S. (39.6 vs. 40.0), whereas in Maryland and Virginia the industrial sector accounts for merely ten to fifteen percent of total electricity usage. On the other hand, Maryland and Virginia have very large residential sectors.

Table I-13

Growth in Energy and Peak Demand on the Delmarva Peninsula
(Thousands of MWh)

				Average Annual Growth Rates	
	1966	1973	1980*	1966-1973	1973-1980
Residential	1,063	2,136	2,682	10.5%	3.3%
Commercial	1,025	1,969	2,387	9.8	2.8
Industrial	1,510	2,513	2,430	7.6	-0.5
Total	3,752	6,958	8,109	9.2	2.2
Peak Demand (MW)	752	1,540	1,698	10.8	1.4

* Estimates. 1980 peak demand is weather adjusted.

Clearly, a precipitous decline in energy sales and peak demand growth rates has taken place since 1973. This tendency can be explained by the various forces which have operated nationwide -- sluggish economic growth, responses to higher energy prices and so forth. But a prominent part of the explanation lies in the stagnant industrial power demands. (Note that 1980 industrial sales were actually below those in 1973.) The long-run outlook for heavy manufacturing industry in Delaware is one of virtually no growth. Because of the importance of this sector, overall system demand growth will be restrained.

<u>The Allegheny Power System</u>

APS is a holding company whose principal operating subsidiaries are The Potomac Edison Company (PE), The Monongahela Power Company (MP) and The West Penn Power Company. These three companies serve a sprawling, largely rural service territory which extends over five states, approximately 86 counties and 29,000 squares miles. Approximately 2.6 million people live in this geographic region. The rural nature of the system is attested to by the fact that the largest city in the APS service territory, Parkersburg, West Virginia, has a population of about 44,000.

Potomac Edison operates in western Maryland, the eastern West Virginia panhandle, and the northwestern portion of Virginia. Monongahela Power serves the northern half of West Virginia and a small area in eastern Ohio along the Ohio River. West Penn serves the southwest and central areas of Pennsylvania. The relative sizes of the three companies and the various regulatory jurisdictions are shown in Table I-14 below.

Table I-14

1977 Energy Sales
(Thousands of MWh)

Company	Sales	%of APS	1965-1977 Annual Growth Rate
Potomac Edison	7,815.1	27.7%	10.7%
Maryland	5,628.8	19.9	11.9
Virginia	1,096.4	3.9	9.1
W. Virginia	1,089.9	3.9	6.9
Monongahela Power	7,198.0	25.5	6.0
W. Virginia	6,704.7	23.7	5.9
Ohio	493.3	1.7	7.4
West Penn	13,234.1	46.9	4.6
APS	28,247.3	100.0	6.3

On the basis of energy sales, West Penn is the single largest portion of the system; PE and MP are approximately equal in size. The Ohio and Virginia service areas of APS are quite small compared to those in Maryland, Pennsylvania and West Virginia. From the above table it is apparent that power demands in the various areas have been growing at different rates. Between 1965 and 1977, PE (Maryland) grew by nearly 12 percent per year compared to less than five percent for West Penn. The rather extraordinary growth in Maryland is partly explained by the establishment of the Eastalco Aluminum Company plant in 1970 near Frederick. As of 1977 that single customer represented nearly a third of the Maryland load and approximately a fifth of the total Potomac Edison load.

It should also be noted that APS serves several municipals and cooperatives in its service territory on a wholesale basis. In 1977 the APS companies sold 737 thousand MWh to 13 resale customers, the largest being Hagerstown, Maryland. However, those sales represented only about 2.6 percent of the System's energy sales.

APS serves a vast rural region containing small towns and a few small cities. Despite the absence of large cities in the service area, agriculture is relatively unimportant (less than six percent of total employment) compared to heavy manufacturing. APS serves a rather large industrial load due to the predominance of electricity intensive industries in the area such as steel, aluminum, chemicals, glass and coal mining. The employment shares shown below demonstrate that the structure of APS service area economy is not atypical of the rest of the nation.

Table I-15

Employment Shares by Major Sector, 1977

	Potomac Edison	Monongahela Power	West Penn	APS	US
Agriculture	7.2%	6.1%	4.8%	5.9%	3.6%
Mining	0.7	6.3	4.1	3.9	0.9
Manufacturing	23.9	15.6	24.4	21.8	21.7
Trade	19.2	21.8	16.8	18.6	20.4
Government	15.2	16.3	16.2	16.0	16.7
Other	33.7	33.9	33.7	33.8	36.7

Source: Bureau of Economic Analysis unpublished county level employment data.

These figures demonstrate that agriculture and coal mining are far more important activities in the APS service area than nationwide; but employment shares in the other major sectors compare rather closely with those of the U.S. Even though the manufacturing share is virtually identical to the U.S. average, manufacturing activity in this region has been disproportionately concentrated in the energy intensive industries. As of 1977 nearly 75 percent of the industrial electricity sales revenues came from a few, very energy intensive industries -- coal mining; stone, clay and glass; primary metals; paper and chemicals. Nationwide, these industries account for about 50 percent of industrial electricity sales revenues.

The pattern of electricity sales reflect the nature of the APS service territory economy. A breakdown of electricity sales by major customer class for APS and the U.S. shown below for 1977 reveal dramatic differences.

	APS	U.S.
Residential	28.7%	33.2%
Commercial	15.1	23.1
Industrial	53.3	40.0
Other	2.9	3.7

The combination of a concentration of heavy industry and the lack of any major commercial centers is largely responsible for the pattern of APS sales shown above. Also, the relatively mild summer climate and lower than average per capita incomes tend to hold down residential usage relative to the rest of the U. S.

Although the customer class distribution of electricity sales is quite different from the rest of the nation, historical sales growth experience for APS has been quite typical. Prior to 1973 sales and peak demand were growing rapidly. A slight decline in demand occurred during the 1974-1975 period, and demand since then has been growing sluggishly. The slowdown in demand experienced by APS has been for substantially the same reasons as for the rest of the electric utility industry. In addition, however, demand has reflected the poor performance of the steel industry, in recent years, upon which the service area economy is highly dependent. As the figures in Table I-16 demonstrate, the post-1973 decline in demand has been sharpest for industrial customers.

It is also interesting to note that peak demand has grown more rapidly than energy sales since 1973. The figure listed for 1973 is the peak demand for the winter of 1973-1974 -- in the midst of the Arab oil embargo. The 1973 energy sales figure is for the calendar year and therefore largely pre-embargo. This tends to exaggerate post-1973 peak demand growth somewhat. Further, it has been the nonindustrial sales which are the fastest growing part of the system. Since these customers tend to have lower load factors (and higher coincidence factors) than the system average, this has also caused peak to grow more rapidly than energy. Despite the deterioration which has occurred over the past few years, APS still maintains a relatively high system load factor, especially compared to the other Maryland utilities.

Table I-16

Growth of Energy and Peak Demand for the
Allegheny Power System
(Thousands of MWh)

	1966	1973	1980	Average Annual Growth Rates 1966-1973	1973-1980
Residential	3,711	6,614	8,633	8.6%	3.9%
Commercial	1,865	3,621	4,631	9.9	3.6
Industrial	8,822	13,760	15,808	6.6	2.0
Total	14,712	24,672	29,958	7.7	2.8
Peak Demand (MW)	2,661	4,230	5,564	6.2	4.0
Load Factor	68.7%	71.7%	66.8%		

Summary of Economic and Electricity Usage Trends

The historical power demand experience facing the four major utility systems is summarized in Table I-17. Detailed data tables for both historical and projected demands are presented in tables at the end of this chapter.

Table I-17 reveals important similarities in the patterns of demand growth for the four systems. From 1966 to 1973 energy sales and peak demand grew at annual average rates of 8.0 percent and 8.4 percent, respectively, for the four major systems combined. Demand fell in 1974 and 1975 and resumed its growth thereafter though at a slower pace than in earlier years. Between 1973 and 1980 demand growth averaged only 2.6 percent per year.

Table I-17

Historic Energy Sales And Peak Demand Of
The Major Utility Systems
(MW and Thousands MWh)

	BG&E		PEPCO		DP&L		APS		TOTAL	
	Sales	Peak	Sales*	Peak	Sales	Peak	Sales	Peak	Sales	Peak
1966	8,653	1,817	7,639	2,123	3,638	661	14,712	2,661	34,642	7,262
1970	11,971	2,496	11,183	2,908	5,440	1,045	20,119	3,785	48,713	10,234
1973	14,341	3,334	13,645	3,680	6,756	1,489	24,672	4,230	59,414	12,733
1974	13,990	3,190	12,526	3,502	6,592	1,429	24,944	4,272	58,052	12,393
1975	13,857	3,256	13,064	3,623	6,393	1,443	23,962	4,650	57,276	12,972
1976	14,758	3,234	13,444	3,500	6,660	1,301	26,704	5,031	61,566	13,066
1977	15,462	3,588	14,020	3,857	6,906	1,499	28,247	5,174	64,635	14,118
1978	16,170	3,553	14,469	3,714	7,248	1,476	28,733	5,335	66,620	14,078
1979	16,823	3,621	14,651	3,804	7,492	1,501	30,377	5,272	69,343	14,198
1980	17,228	3,969	15,451	4,142	7,460	1,581	29,958	5,564	70,097	15,256

Annual Rates Of Growth

1966-1973	7.48%	9.06%	8.64%	8.18%	9.25%	12.30%	7.67%	6.85%	8.01%	8.35%
1973-1980	2.65	2.52	1.79	1.70	1.43	0.86	2.79	3.99	2.39	2.62
1966-1980	5.04	5.74	5.16	4.89	5.26	6.43	5.20	5.41	5.16	5.45

*Excludes sales to SMECO.

E. The Outlook for Growth in Power Demands

It is expected that future power demand growth will more closely resemble the post-embargo growth rates than those occurring in the decade before 1974. There are several reasons for this expectation. First, a continuation of the economic slowdown of the 1970's, in comparison to the more rapid economic expansion of the 1960's, is projected for the future. As Table I-18 indicates, population and employment growth rate projections for the 1980's are similar to or even below those experienced in the 1970's.[1] The Bureau of Economic Analysis (BEA) is projecting that real per capita income in Maryland will increase by only 2.3 percent annually over the next two decades (8). Finally, the tendency during the 1970's for manufacturing (particularly heavy, energy intensive manufacturing) to decline in absolute terms is expected to continue in the service territories of the major utilities.

Perhaps the most obvious and important reason for the decline in demand growth was the massive increases in energy prices during the mid and late 1970's. The historical price behavior and future outlook are shown in Table I-19. Even if future real price increases do not occur, the massive price increases which have already taken place will suppress future demand. This is because many years are required before consumers can fully adjust to price changes. Thus, during the 1980's consumers will still be adjusting their energy usage to the price shocks of the 1970's. It is also reasonable to expect that future real increases in electric rates for these systems will occur, and continued customer adjustment will follow.

Finally, attitudes and public policy concerning energy usage (and power usage) have changed. Toward the end of the 1970's several important legislative initiatives were enacted designed to require, fund or encourage conservation. Although less potent than the slow economic growth and rising energy prices, these numerous new conservation programs will help to slow the growth of power demands.

The Power Plant Siting Program (PPSP), in cooperation with the Department of the State Planning (DSP), has maintained a program of conducting independent long-range load forecasts. Such studies have been undertaken for each of the four major utilities (9), (10); (11), (12). The DP&L and APS studies were completed relatively recently; however the Pepco and BG&E studies were completed in 1974 and 1977 and were partially updated in 1978 and 1981, respectively. It is anticipated that both studies will be updated and substantially revised in 1982.

The PPSP/DSP load forecasts were developed through the application of econometric models (see Appendix A). This methodology involves two principal stages. In the first stage, statistical models of the demand for electricity are estimated from historical data. These econometric models describe the relationship between the demand for electricity and the various factors (i.e., the explanatory variables) that govern it, such as population, employment, climate, income and electricity rates. In the second stage, projected or assumed

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[1] The employment projections shown were prepared in 1978 and are therefore somewhat dated. The most recent BEA figures (November 1980) project employment in the State of Maryland to increase by only 1.2 percent annually.

Table I-18

Population and Employment Trends, 1970-1990
(Thousands)

Service Area	1970	1980	1990	Annual Rate of Growth 1970-1980	1980-1990
Population					
Pepco	2,062	2,090	2,196		
(Md. only)	1,300	1,411	1,525	0.82%	0.81%
BG&E	2,071	2,174	2,296	0.49	0.55
Delmarva	800	879	959	0.94	0.87
(Md. only)	205	236	257	1.42	0.86
APS	2,495	2,636	2,797	0.55	0.59
(Md. only)	294	334	366	1.28	0.92
Maryland	3,924	4,216	4,510	0.72	0.67
Employment* (nonagricultural)					
Pepco	1,058.6	1,168.7	1,434.4	1.42%	1.59%
(Md. only)	411.6	514.7	728.4	3.24	2.71
BG&E	885.8	949.1	1,191.1	0.99	1.76
Delmarva	344.2	381.4	486.8	1.48	1.89
(Md. only)	92.8	105.9	127.8	1.90	1.46
APS	832.0	936.5	1040.0	1.70	0.81
(Md. only)	112.7	127.6	139.4	1.79	0.68
Maryland	1,519.0	1,709.0	2,216.1	1.70	2.02

* Employment figures in the 1980 column are 1977.

Source: (8), (9), (10), (11), (12)

Table I-19

Monthly Residential Electric Bills*

Service Area	1972	1980	1990	Annual Rate of Growth 1972-1980	Annual Rate of Growth 1980-1990
Pepco	$10.35	$29.62	--	14.1%	--
(CPI Adjusted)	10.35	15.92	18.28	5.5	1.4%
BG&E	15.30	28.11	--	7.9	--
(CPI Adjusted)	15.30	15.11	18.41	-0.2	2.0
DP&L	13.19	36.11	--	13.4	--
(CPI Adjusted)	13.19	19.40	20.80	4.9	0.7
Potomac Edison	10.62	27.12	--	12.4	--
(CPI Adjusted)	10.62	14.57	15.24	4.0	0.5
Maryland	13.82	28.57	--	9.5	--
(CPI Adjusted)	13.82	15.35	--	1.3	--

*Bills are based upon 500 kwh per month on January 1 of designated year. Bills are for Maryland portions of service area only.

Source: (13)

future values of the explanatory variables are inserted into the estimated model, and the forecast is then calculated for each year. Peak demand is forecasted in a similar manner except that total energy usage is used as an important explanatory factor in the peak demand equation. Thus, energy forecasts must first be developed in order to calculate the peak demand forecast.

In all of the PPSP/DSP forecast studies prepared to date, electricity sales models have been estimated separately for the residential and non-residential classes of customers. Moreover, models were separately estimated for the residential class, nonresidential class and system peak demand for the summer and winter seasons, since behavioral relationships and some of the underlying determinants differ between the two seasons. In all cases the models were estimated using ordinary least squares regression -- in some cases using quarterly or monthly time series data and in other cases using pooled time series/cross section data.

The resulting forecasts are heavily influenced by the projections of and assumptions on future values of the explanatory variables. To the extent possible, these values were obtained from official, published sources. Where official sources did not exist, future values were developed judgmentally (see Appendix A).

Table I-20 provides the energy and annual peak demand forecasts prepared by PPSP for the four major electric utility systems. Historical growth rates of power demands are included in this table for purposes of comparison. Forecasts for the Maryland portions of APS and DP&L are shown along with the aggregate totals both with and without the non-Maryland demands. The figures for the Maryland jurisdiction portions are not very meaningful to utility system planners since each of these utilities plans its generation investments strictly on a system-wide basis without regard to jurisdictional patterns of demand.

There is significant variation among the forecasts for the four systems. Pepco's peak demand is projected (updated forecast) to grow by less than one percent annually compared to 3.3 percent for BG&E.[1] APS and DP&L, the two most recent studies prepared by PPSP, are between these two extremes. With the exception of the BG&E forecast of energy sales (which was completed in 1977), the forecasted growth rates are roughly comparable to those occurring between 1973 and 1980. This is not a surprising result. Future economic and population expansion in the service areas of the Maryland utilities is not expected to be any more rapid than in the 1970's. However, even though future energy prices are expected to rise in real terms, a 1970's type price explosion is assumed not to reoccur. Thus, growth rates slightly in excess of those occurring during the 1973-1980 period are plausible.

The PPSP/DSP forecasts in Table I-20 are each based upon a carefully formulated set of assumptions regarding the future behavior of the variables appearing in the demand equations. Those sets of assumptions are referred to as the Most Likely Case (MLC). In each case the MLC scenario is based upon official projections from federal and state agencies along with PPSP's best judgment

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[1] The BG&E peak demand forecast in Table I-20 is a revision of an original study prepared by PPSP. However, the energy projections shown in that table have not yet been revised. That accounts for the large discrepancy in the peak demand and energy sales growth rates.

Table I-20

Projected Energy Sales and Peak Demand
For Major Maryland Utilities[a]
(Thousands MWh and MW)

	1982		1985		1990		Annual Rates of Growth 1973-1980		1982-1990	
	Sales	Peak	Sales	Peak	Sales	Peak	Sales	Peak	Sales	Peak
Pepco	15,828	4,284	16,824	4,393	18,599	4,554	2.22%	1.70%	2.04%	0.74%
BG&E	19,586	4,028	23,049	4,447	30,021	5,232	2.65	2.52	5.48	3.32
DP&L[b]	8,099	1,687	8,996	1,919	10,250	2,246	2.21	0.86	2.65	3.23
(MD Portion)	1,515	454	1,697	503	1,995	592	5.29	3.99	3.50	3.37
APS	31,394	5,726	33,997	6,294	38,251	7,236	2.79	3.99	2.50	2.96
(MD Portion)	6,014	1,063	6,488	1,181	7,384	1,405	5.59	5.01	2.60	3.55
MD Total[c]	42,943	9,829	48,058	10,524	57,999	11,783	2.96	2.44	3.83	2.29
Total	74,907	15,725	82,866	17,053	97,121	19,268	2.57	2.84	3.30	2.57

(a) PPSP/DSP forecasts.

(b) Includes entire Delmarva Peninsula.

(c) Includes non-Maryland portions of Pepco.

Source: Tables I-24 through I-35.

concerning those variables for which official projections are not available. Also, every effort is made to assure that the various assumptions in each case are logically consistent with one another.

Some of the sources of these projections have been referred to earlier. BEA has been relied upon for projections of real per capita income, and outside of Maryland, for employment projections. Population and household formation projections (utilized to determine residential customers) have been obtained from the U.S. Census Bureau. Within Maryland, the Department of State Planning projections of employment and population have been utilized. Finally, electric energy price projections have been determined on a largely judgmental basis, but taking into consideration national EIA fuel price projections along with the specific circumstances of the utility system under study.

The usage of the projections figures available from these sources introduces a large element of uncertainty into the load forecasts.[1] It is important that this uncertainty be recognized and explicitly incorporated into the planning process. In order to gauge the magnitude of forecast uncertainty, various alternative scenarios are constructed, including a "conservation case" scenario. Upper and lower bound load growth rates are obtained by determining the extreme, plausible modification to the MLC assumptions and recalculating the forecasts. For example, the DP&L MLC peak demand growth rate forecast is 3.2 percent per year, surrounded by upper bound of 4.3 percent and a lower bound of 1.8 percent. Clearly, the range of uncertainty is quite large.

Table I-21 provides a comparison between the PPSP and Company prepared peak demand forecasts through 1990. With some minor exceptions, the independent peak demand forecasts prepared by PPSP are quite similar to those prepared by the Companies. For all four major systems combined the difference is roughly 400 megawatts or less than one year's load growth. This discrepancy is well within any reasonable range of uncertainty.

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[1] Uncertainty over forecast assumptions is only one problem of many involved. For example, the models themselves may be in error to some degree. However, assumption error is probably the most serious problem in forecasting and the greatest source of uncertainty.

Table I-21

Comparisons Of PPSP/DSP And Company Prepared Peak Demand Forecasts
(MW)

	1982		1985		1990			Annual Rates of Growth(%)		
								1973-1980	1982-1990	
	PPSP	Company	PPSP	Company	PPSP	Company	Difference(%)		PPSP	Company
Pepco	4,284	3,956	4,393	4,105	4,544	4,355	4.2%	1.70%	0.74%	1.21%
BG&E	4,028	4,130	4,447	4,530	5,232	5,130	1.9	2.52	3.32	2.75
DP&L(a)	1,547	1,627	1,694	1,767	1,951	1,918	1.7	0.86	2.94	2.08
(MD Portion)	454	407	503	480	570	517	9.3	3.99	2.89	3.04
APS	5,726	5,689	6,294	6,202	7,236	7,182	0.8	3.99	2.97	2.96
(MD Portion)	1,063	1,050	1,181	1,195	1,405	1,460	-4.3	5.01	3.61	4.33
MD Total(b)	9,829	9,543	10,524	10,310	11,751	11,462	2.4	2.44	2.26	2.32
Total	15,585	15,402	16,828	16,604	18,963	18,585	2.0	2.84	2.48	2.38

(a) Figures exclude Dover and Easton load not served by DP&L and the Getty Oil Refinery load. The 1990 figures are lowered by 50 megawatts to reflect capacity purchase by The Old Dominion Electric Coop. (The Maryland portion load projections for 1990 are lowered by 22 megawatts for the acquisition of capacity by Old Dominion Electric Cooperative.)

(b) Includes non-Maryland portions of Pepco. Excludes Conowingo Power Company.

Source: Table I-20, (14), (15), (16), (17).

F. The Management of Demand

System planning has traditionally involved determining the optimal scheduling and mix of plant types (i.e. base load, cycling or peaker) and fuel types which will minimize the total costs of producing power, while at the same time providing reliable service. This is a complicated process and relies heavily upon the outlook for the growth of power demand. With the rapid increases in recent years in the cost of boiler fuel, generation facilities and financing, it is becoming increasingly obvious that the least-cost approach in planning will involve programs and measures to reduce energy demand (or at least the growth in energy demand) and flatten load curves.[1]

Many utility systems recognize and are pursuing the demand-side alternatives. The Duke Power Company has been pursuing an ambitious demand management program explicity in its generation plans. It has identified more than 25 such programs including new home insulation standards, direct load control and time-of-day rates, which could result in amazingly large benefits. The Company's Annual Report to Stockholders states:

> Over the next 14 years, Duke Power has the opportunity to avoid an investment of more that $10 billion.
>
> The Company's comprehensive Load Management Program is designed to do just that by reducing the incremental growth of peak demand 5,635,000 kilowatts by 1994 - nearly the equivalent of 5 generating units the size of McGuire 1. (18)

There are two basic approaches to managing power demands -- conservation and load management.[2] Conservation simply refers to the reduction in use of electricity that can be achieved by better weatherization, improved appliance efficiencies or by choosing a less energy intensive lifestyle. Load management is only concerned with when electricity is consumed and not total usage. Load management can achieve greater system efficiencies by shifting usage from times

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[1] There are other factors which also argue for seeking alternatives to construction of central station generating facilities -- environmental difficulties and financial distress. Environmental impacts of electric power generation (and industrial activity generally) has led to environmental legislation. This legislation has tended to increase power plant licensing time and has to some extent increased the length of the construction period. Both effects have contributed to lengthening the lead times necessary to bring new power plants on-line. Environmental litigation has also led to unanticipated delays in bringing facilities on-line (as in the case of APS's proposed Davis pumped storage hydro project) or even to out-right cancellations. High interest rates may make it difficult for utilities to carry large, expensive construction projects for long time periods.

[2] From the utilities point of view, production of power by the customer such as solar or wind energy also lessens demands, if that power replaces purchased power. However, since these technologies produce electricity they are discussed in Chapter II.

when additional energy is expensive to produce (or when demand is pressing against capacity) to times when additional energy is cheap (or when there is excess capacity). Approaches which would facilitate such load shifting include thermal storage technologies, appliance cycling controls, time-of-use pricing and interruptible rates.

There is mounting evidence that in many instances conservation is extremely cost-effective. However, there are numerous institutional barriers that tend to prevent economically justified conservation measures from being undertaken by consumers. These would include difficulty in obtaining information concerning costs and benefits of conservation; the setting of utility rates at historic costs rather than marginal costs (i.e. the costs of producing and providing additional power); rapid ownership turnover of homes; and the unwillingness of financial institutions to provide conservation loans at reasonable rates. These problems can be mitigated to some extent by utility and governmental programs.[1]

Weatherization

Improved weatherization of residential structures may be one of the most cost-effective methods of reducing expensive energy usage for homes which heat and/or cool with electricity. The following data from BG&E shown in Table I-22 illustrate this point.

Potential weatherization benefits were confirmed in a recent study of electricity usage in New York State. That study estimates that implementing weatherization measures, as compared to typical current practice, would reduce electricity used for space cooling by about 5 percent (20).

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[1] For a description of the many State and Federal programs operating in Maryland see: Energy in Maryland, Maryland Energy Administration, January 1981, pp.18-49.

Table I-22

Annual Electric Bill Savings for a "Typical Home" Served By BG&E

	Electric Resistance Heat	Heat Pumps	Electric A/C
Caulking & Weather-stripping	$33-$50	$25-$35	$3-$5
Wall Insulation	$65-$100	$36-$56	$10-$16
Floor Insulation	$66-$101	$36-$56	$0
Duct Insulation	NA	$29-$44	NA
Storm/Thermal Windows	$59-$91	$33-$50	$4-$6
Storm/Thermal Doors	$33-$51	$18-$28	$1-$2
Ceiling Insulation	$429-$600	$239-$367	$102-$157
Clock Thermostat	$42-$65	NA	$9-$14

Source: (19)

The California Energy Commission has estimated that a fairly modest investment in weatherization could save electric heat customers in California 1,800 to 3,000 kWh annually. The same study reports that The Pacific Power & Light Company (PP&L) estimates that a somewhat larger weatherization investment in a typical, electrically heated home in its Oregon service territory could save 5,000 kWh per year (21).

PP&L and Pacific Gas & Electric Company (PG&E) have implemented agressive programs to subsidize such investments. Under both programs, the utility, with the customer's consent, arranges and pays for the weatherization of a customer's home. There is no cost to the customer until the home is sold, at which point the original owner must repay the principal. The utility, however, absorbs all interest costs. PP&L and PG&E believe that these weatherization subsidies will have the effect of ultimately benefiting all customers since it will lead to large, long run reductions in system costs -- far larger than the amount of the subsidies.

The cost-effectiveness and practicality of such a program depend on a number of specific factors, such as the potential for further weatherization in the service area and the structure of costs of the utility in question. PPSP is conducting a study, jointly funded with the Office of People's Counsel, to determine the possible costs and energy savings impacts such a program might have on the BG&E system. If the results appear promising, the study will be extended to the other utilities in the State.

Even more cost-effective than retrofitting is the weatherization of new homes. In recognizing this fact, several utilities and state governments have proposed rate incentives, hook-up restrictions and information programs to encourage builders and prospective new home owners to build and purchase energy efficient homes. In Maryland, recent legislation has been enacted to ensure that new buildings will meet a minimum set of energy efficiency standards (HB 748).

Load Management

The demand for electricity on a given system varies significantly by season of the year, by day of the week, and by time-of-day. The major utilities in the State, with the exception of APS, have historically exhibited rather low annual load factors. Unless some deliberate efforts are made to change this situation, the low load factors are likely to persist and may even deteriorate further.

The setting of electric rates can play a useful and effective role in both reducing the large, time related variations in load and in encouraging conservation of electric power. This idea has been promoted by utility ratemaking experts and became embodied in Federal energy policy with the 1978 passage of the Public Utilities Regulatory Policies Act (PURPA).

This Act deals with numerous aspects of public utility regulation. It requires state commissions to hold evidentiary hearings and to determine the appropriateness of six principal ratemaking standards. These are:

> Cost of service standard -- Rates charged to each class of customers should reflect the costs of serving each class to the maximum extent practicable. Such determinations should include "marginal costs".
>
> Declining block rate standard -- Unless cost justified, the energy component of an electric rate shall not decrease as kilowatt hour consumption increases.
>
> Time-of-day rate standard -- To the extent practicable, rates should reflect time related variations in cost, unless such rates are determined not to be cost-effective.
>
> Seasonal rate standard -- Electric rates should reflect seasonal differences in cost.
>
> Interruptible rate standard -- Commercial and industrial customers shall be offered interruptible rates which reflect the costs of providing service on an interruptible basis to those customers.
>
> Load management techniques standards -- Utilities shall provide load management techniques found to be cost-effective, practical, and useful to reduce capacity requirements and/or fuel costs.

These rate design standards were established in order to promote the stated purposes of PURPA -- conservation, efficiency and equity. By and large, these goals can be achieved by providing the consumers of electricity with price signals that better reflect the costs of providing additional electric service to them.

Time-of-use (TOU) rates (based upon time-varying marginal costs) can help reduce the growth rate of peak demand, improve system annual load factors and generally flatten load curves. These results naturally occur as customers shift power usage from the peak to the off-peak period. If achieved, the existing generation system can function more efficiently, and capacity additions may be deferred. The fuel cost reduction occurs as the reduction in peak usage (in response to higher peak prices) permits the utility to reduce operation of its more energy inefficient generating units. In that manner TOU rates help to serve the purposes of PURPA.

TOU rate implementation requires a large front-end investment in expensive metering equipment needed to measure energy usage by time period. Consequently, PURPA requires that such rates pass a cost-effectiveness test. TOU rates will only lower system costs if the resulting increase in system efficiency outweigh the additional metering and administrative costs. This question was investigated by PPSP for the BG&E system (22). Benefits were measured as changes in "consumer surplus" when moving from current rates to those reflecting marginal costs by time period. TOU pricing was found to be cost-effective for the average size customer in each class though cost-ineffective for smaller residential customers. It was estimated that the present value of the gains over the lifetime of the metering equipment is roughly $85 million. Since this study relies upon data several years old, and since fuel prices have risen far more rapidly than metering costs, this may represent a substantial understatement of the benefits.

Currently, none of the four utility systems provides time-of-use pricing to its Maryland customers. The PURPA compliance hearings have been held or are currently underway for each utility, but the Public Service Commission has ruled on the ratemaking standards only for BG&E. In the other state jurisdictions in which the Maryland utilities operate time-of-use rates have also been considered, and they have been adopted to a limited extent. The District of Columbia has implemented the rates for the Pepco's approximately 250 largest High Tension customers. The State of Delaware has also moved forward to implement such rates for many of the large industrial concerns. For many years now West Penn Power and Monongahela Power have sold power on a time-of-use basis to some of their industrial customers. However, there appears to be a very large potential to expand time-of-use pricing, on a cost-effective basis, for both the Maryland and non-Maryland portions of the service areas.

Direct load control devices are intended to serve the same purpose as time-of-use rates, but they are generally controlled by the utility rather than the individual customer. There are two basic approaches to direct load control -- heat (or cooling) storage and appliance cycling. With the former, electricity heats water or some other thermal storage medium during the off-peak period. Through the use of a communication device of some sort, the utility shuts off the customer's electric space and/or water heater during the peak period. The other approach, appliance cycling, involves interrupting the service of major appliances -- air conditioners, electric space or water heaters -- for only a few minutes at a time during the periods of maximum demand on a system. Whereas thermal storage systems can save capacity and energy costs, appliance cycling saves little energy cost and is primarily designed to save capacity costs.

Like time-of-use pricing, load control devices can improve system efficiency but require a major investment in facilities to communicate with and control customer appliances. A recent Tennessee Valley Authority (TVA) staff study estimated the costs and benefits of several different proposed load management methods. These results are summarized below on a present value basis through the year 2000.

Table I-23

TVA System Savings From Load Management
(Millions $)

Method	Costs	System Benefits	MW Reduction
Water Heat Cycling	$71-$96	$130	458
Water Heat Storage	11-47	267	627
Space Heat Storage	35-127	335	578
Space Heat Cycling	48-55	129	311

Source: (23)

Several observations concerning direct load control need to be be made. First, interrupting service may involve a certain amount of customer inconvenience. Second, it also appears that heat storage economics is more favorable than cooling storage, thus making it more advantageous for winter peaking systems (such as TVA) but less so for summer peaking systems. Third, since appliance cycling does not save a great deal of energy, it is probably only worthwhile on systems that are capacity constrained. Many systems, such as Pepco, will have excess capacity for many years to come. On excess capacity systems, there appears to be little that direct load control can accomplish that cannot be accomplished by TOU pricing. The latter method allows customers to respond to price signals that follow the time pattern of costs, and is therefore a preferable method of managing system loads. However, there may be an important role for both approaches to load management.

None of the major Maryland utilities currently have direct load control programs of any significance in any jurisdiction. Each of the four utilities plans to examine or has examined the feasibility and impacts from such programs. Pepco, for example, is currently attempting to intitiate a load management experiment in Maryland. However, a preliminary analysis suggests to the Company that implementation is not cost-effective at this time (24). DP&L is currently conducting a two-year experiment of load management techniques and innovative rate structures with 1,000 of its Delaware residential customers. The purpose of the study is to determine customer attitudes and responses to these programs.

Outside of their Maryland service area two utilities, DP&L and APS, have a modest program of curtailable rates (i.e., rates that permit service interruptions) for their large industrial customers. DP&L currently sells power to three customers on interruptible rates, whose potential interruptible loads represent roughly five percent of the Company's system peak demand. APS has roughly 50 megawatts of interruptible load which is less than 1 percent of total system peak demand.

G. Historical and Projected Company Load Data

The last section of this chapter presents detailed statistical data on historical and projected power demands for the four major electric utilities serving Mayland. The historical tables provide annual residential and nonresidential sales, summer and winter peak demand, generating capacity and the reserve margin. Reserve margin is defined as generating capacity minus annual peak demand divided by annual peak demand.

The tables of projected demands provide the same information through 1990. The projections of energy sales and peak demand were prepared by PPSP, and the capacity figures are based upon Companies' latest generation plans. The table also provides the Companies' load forecasts (and thus reserve margin forecasts) for purposes of comparison.

For Delmarva Power & Light Company and the Allegheny Power System, the historical and projected data are provided for both the total system and for the Maryland portions of those systems. The reserve margins have no meaning for the Maryland portions and are therefore not provided.

Table I-24

Historic Energy Sales, Peak Demand
And Generating Capacity For The Allegheny Power System

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	3,711	11,001	14,712	2,425	2,661	2,536	-4.7%
1970	5,319	14,800	20,119	3,206	3,785	4,254	12.4
1971	5,694	15,585	21,279	3,274	3,769	4,731	25.5
1972	6,137	16,678	22,815	3,622	4,039	5,208	28.9
1973	6,614	18,058	24,672	4,040	4,230	5,742	35.7
1974	6,809	18,135	24,944	3,916	4,272	6,388	49.5
1975	7,229	16,733	23,962	3,959	4,650	6,428	38.2
1976	7,524	19,181	26,704	4,284	5,031	6,428	27.8
1977	8,096	20,152	28,247	4,539	5,174	6,428	24.2
1978	8,351	20,382	28,733	4,632	5,335	6,417	20.3
1979	8,466	21,911	30,377	4,676	5,272	6,997	32.7
1980	8,633	21,274	29,958	4,903	5,564	7,568	36.0
			Annual Average Rates of Growth				
1966-1970	9.42%	7.70%	8.14%	7.23%	9.21%	13.81%	
1970-1975	6.33	2.48	3.56	4.31	4.20	8.61	
1975-1980	3.61	4.92	4.57	4.37	3.65	3.32	
1966-1980	6.22	4.82	5.21	5.16	5.41	7.56	

Peak demand figures are for winter beginning in designated year.

Table I-25

Projected Energy Sales, Peak Demand And
Generating Capacity For The Allegheny Power System

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Winter Peak (MW)	R.M.(%)
1981	8,793	21,718	30,511		5,552	7,587	36.7%	5,445	39.3%
1982	9,194	22,200	31,394		5,726	7,600	32.7	5,689	33.6
1983	9,602	22,657	32,259		5,910	7,600	28.6	5,798	31.1
1984	10,022	23,106	33,128		6,093	7,600	24.7	6,024	26.2
1985	10,447	23,550	33,997		6,294	8,020	27.4	6,202	29.3
1986	10,853	23,975	34,828		6,443	8,446	31.0	6,448	30.9
1987	11,260	24,401	35,661		6,626	8,440	27.4	6,628	27.3
1988	11,676	24,836	36,512		6,810	8,440	23.9	6,806	24.0
1989	12,099	25,271	37,370		7,000	9,070	29.6	6,933	30.8
1990	12,526	25,725	38,251		7,236	8,995	24.3	7,182	25.2
Annual Average Rates of Growth									
1980-1985	3.88%	2.05%	2.56%		2.50%	1.17%		2.19%	
1985-1990	3.70	1.78	2.39		2.83	2.32		2.98	
1980-1990	3.79	1.92	2.47		2.66	1.74		2.59	

* Projections prepared by PPSP.
Peak demand figures are for winter beginning in designated year.

Table I-26

Historic Energy Sales, Peak Demand And
Generating Capacity For The Potomac Edison Company (Maryland Portion)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity*	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	489	932	1,421		336	227	
1970	731	2,104	2,835		550	143	
1971	788	2,775	3,563		601	142	
1972	851	2,908	3,759		656	142	
1973	930	3,080	4,010		682	139	
1974	985	3,004	3,990		693	139	
1975	1,065	2,889	3,954		802	139	
1976	1,142	4,164	5,306		916	139	
1977	1,235	4,394	5,629		1,018	139	
1978	1,267	4,231	5,498		981	129	
1979	1,276	4,554	5,830		961	129	
1980	1,289	4,580	5,869		960	117	
			Annual Average Rates of Growth				
1966-1970	10.58%	22.58%	17.24%		13.11%	-10.9%	
1970-1975	7.82	6.55	6.88		7.84	-0.6	
1975-1980	3.89	9.65	8.22		3.66	-3.4	
1966-1980	7.14	12.04	10.66		7.79	-4.6	

Peak demand figures are for winter beginning in designated year.

* Does not include the Potomac Edison Company share of jointly-owned stations located in Pennsylvania and West Virginia, or the wholly-owned stations in Virginia.

Table I-27

Projected Energy Sales, Peak Demand And
Generating Capacity For The Potomac Edison Company (Maryland Portion)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Winter Peak (MW)	R.M.(%)
1981	1,355	4,517	5,872		1,021	117		1,015	
1982	1,452	4,562	6,014		1,063	117		1,050	
1983	1,555	4,610	6,165		1,098	117		1,085	
1984	1,665	4,658	6,323		1,141	117		1,140	
1985	1,781	4,707	6,488		1,181	117		1,195	
1986	1,897	4,757	6,654		1,225	117		1,255	
1987	2,018	4,807	6,825		1,269	117		1,295	
1988	2,146	4,858	7,004		1,309	117		1,350	
1989	2,280	4,910	7,190		1,355	117		1,405	
1990	2,421	4,963	7,384		1,405	117		1,460	
			Annual Average Rates of Growth						
1980-1985	6.69%	0.55%	2.03%		4.23%	0.0%		4.48%	
1985-1990	6.33	1.06	2.62		3.53	0.0		4.09	
1980-1990	6.51	0.81	2.33		3.88	0.0		4.28	

*Projections prepared by PPSP.

Peak demand figures are for the winter beginning in designated year.

Capacity data does not include the Potomac Edison Company share of jointly-owned stations located in Pennsylvania and West Virginia or the wholly-owned stations in Virginia.

Table I-28

Historic Energy Sales, Peak Demand And
Generating Capacity For The Baltimore Gas And Electric Company

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	2,347	6,306	8,653	1,817	1,422	1,866	2.7%
1970	3,665	8,306	11,971	2,496	1,954	2,791	11.8
1971	3,864	8,620	12,485	2,605	2,053	3,303	26.8
1972	4,102	8,889	12,991	2,960	2,059	3,748	26.6
1973	4,618	9,723	14,341	3,334	2,302	3,541	6.2
1974	4,469	9,251	13,990	3,190	2,177	3,410	6.9
1975	4,664	9,194	13,857	3,256	2,301	4,046	24.3
1976	4,888	9,870	14,758	3,234	2,418	4,241	31.1
1977	5,231	10,230	15,462	3,588	2,640	4,995	39.2
1978	5,435	10,735	16,170	3,553	2,850	4,995	40.6
1979	5,497	11,327	16,823	3,621	2,900	4,995	37.9
1980	6,005	11,223	17,228	3,969	3,046	5,010	26.2
			Annual Average Rates of Growth				
1966-1970	11.79%	7.14%	8.46%	8.26%	8.28%	10.59%	
1970-1975	4.94	2.05	2.97	5.46	3.32	7.71	
1975-1980	5.18	4.07	4.45	4.04	5.77	4.37	
1966-1980	6.94	4.20	5.04	5.74	5.59	7.31	

Table I-29

Projected Energy Sales, Peak Demand And
Generating Capacity For The Baltimore Gas And Electric Company

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve Margin(%)	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)		Summer Peak	R.M.(%)
1981	5,824	12,719	18,543	3,897		5,025	29.0%	3,970	26.6%
1982	6,122	13,464	19,586	4,028		5,025	24.8	4,130	21.7
1983	6,446	14,234	20,681	4,162		5,025	20.7	4,260	18.0
1984	6,797	15,036	21,833	4,303		5,594	30.0	4,390	27.4
1985	7,175	15,874	23,049	4,447		5,634	26.7	4,530	24.4
1986	7,577	16,713	24,290	4,591		5,759	25.4	4,640	24.1
1987	8,008	17,596	25,604	4,741		5,701	20.3	4,740	20.3
1988	8,469	18,525	26,994	4,897		6,321	29.1	4,870	29.8
1989	8,961	19,503	28,464	5,031		6,321	25.6	5,000	26.4
1990	9,486	20,535	30,021	5,232		6,321	20.8	5,130	23.2
				Annual Average Rates of Growth					
1980-1985	3.62%	7.18%	6.00%	2.30%		2.38%		2.68%	
1985-1990	5.74	5.28	5.43	3.30		2.33		2.52	
1980-1990	4.68	6.23	5.71	2.80		2.35		2.60	

* Projections prepared by PPSP.

Table I-30

Historic Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Total System)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	839	2,799	3,638	661	639	799	12.5%
1970	1,280	4,610	5,440	1,014	943	1,151	13.5
1971	1,381	4,367	5,748	1,090	1,002	1,184	8.6
1972	1,464	4,777	6,241	1,262	1,150	1,364	8.1
1973	1,630	5,126	6,756	1,434	1,076	1,552	8.2
1974	1,597	4,995	6,592	1,375	1,140	1,624	18.2
1975	1,672	4,721	6,393	1,397	1,155	1,905	36.4
1976	1,788	4,872	6,660	1,301	1,278	1,917	47.4
1977	1,925	4,981	6,906	1,450	1,352	1,998	37.8
1978	1,980	5,268	7,248	1,428	1,339	1,993	39.6
1979	1,968	5,524	7,492	1,452	1,322	1,993	37.3
1980	2,047	5,413	7,460	1,529	1,444	2,008	31.3
			Annual Average Rates of Growth				
1966-1970	11.14%	10.41%	10.58%	9.32%	10.22%	7.57%	
1970-1975	5.49	2.56	3.28	6.62	4.14	10.60	
1975-1980	4.13	2.77	3.14	1.82	4.57	1.06	
1966-1980	6.58	4.82	5.26	5.63	6.00	6.80	

Data represent the entire DP&L System and exclude energy sales to Easton and includes portions of Dover and Easton peak demand provided by DP&L generation. Data exclude capacity from and loads served by Delaware City 1 and 2 (dedicated to Getty Refinery).

Table I-31

Projected Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Total System)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Summer Peak(MW)	R.M.(%)
1981	2,022	5,028	7,059	1,506	1,406	2,219	47.3%	1,531	44.9%
1982	2,100	5,107	7,226	1,547	1,453	2,234	44.4	1,627	37.3
1983	2,183	5,212	7,423	1,594	1,504	2,167	40.0	1,667	30.0
1984	2,270	5,333	7,641	1,641	1,557	2,167	32.1	1,711	26.7
1985	2,363	5,464	7,874	1,694	1,594	2,217	30.9	1,767	25.5
1986	2,437	5,584	8,075	1,749	1,640	2,217	26.8	1,808	22.6
1987	2,515	5,711	8,286	1,808	1,688	2,177	20.4	1,818	19.8
1988	2,597	5,841	8,505	1,869	1,757	2,177	16.5	1,870	16.4
1989	2,682	5,978	8,734	1,934	1,808	2,177	12.6	1,919	13.4
1990	2,770	6,118	8,970	1,951	1,819	2,502	28.2	1,918	30.5
			Annual Average Rates of Growth						
1980-1985	2.91%	0.19%	1.09%	2.07%	1.37%	2.00%		2.94%	
1985-1990	3.23	2.29	2.64	2.87	2.68	2.45		1.65	
1980-1990	3.07	1.23	1.86	2.47	2.02	2.22		2.29	

* Projections prepared by PPSP.
Peak demand figures are for the winter beginning in designated year.
Energy sales figures exclude sales to Easton and Dover. Peak figures include the portion of Easton and Dover load provided by DP&L generation. Peak load and capacity figures exclude the Getty Refinery loads and the Delaware City 1 and 2 capacity, respectively. The 1990 peak loads are reduced by 50 megawatts to reflect the sale of capacity from the Vienna 9 plant to the Old Dominion Electric Cooperative.

Table I-32

Historic Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Maryland Portion)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin %
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	199	299	498	141	116	105	
1970	322	451	773	210	206	132	
1971	355	480	835	227	227	282	
1972	389	511	900	278	233	282	
1973	441	564	1,005	327	290	252	
1974	458	569	1,027	319	275	252	
1975	483	593	1,076	342	294	252	
1976	543	648	1,190	315	347	252	
1977	624	733	1,357	384	400	252	
1978	654	776	1,430	377	400	252	
1979	650	778	1,428	402	388	252	
1980	669	773	1,442	430	-	252	
			Annual Average Rates of Growth				
1966-1970	12.78%	10.80%	11.62%	10.47%	15.44%	4.68%	
1970-1975	8.45	5.62	6.85	10.25	7.37	13.81	
1975-1980	6.73	5.44	6.03	4.69	-	0.0	
1966-1980	9.05	7.02	7.89	8.29	-	6.45	

* Peak demand figures are for winter beginning in designated year.
Energy sales figures exclude sales for resale and sales to Easton. Peak demand figures include the portion of Easton peak served by DP&L generation.

Table I-33

Projected Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Maryland Portion)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Summer Peak(MW)	R.M.(%)
1981	661	800	1,461	443		252		391	
1982	688	826	1,515	454		177		452	
1983	717	854	1,573	468		177		457	
1984	749	882	1,633	485		177		467	
1985	782	913	1,697	503		177		480	
1986	804	945	1,751	518		177		490	
1987	829	978	1,809	535		177		503	
1988	854	1,013	1,868	553		177		516	
1989	880	1,048	1,930	572		177		528	
1990	908	1,086	1,995	570		502		517	
Annual Average Rates of Growth									
1980-1985	3.18%	3.38%	3.31%	3.18%		-6.82%		2.22%	
1985-1990	3.03	3.53	3.29	2.53		23.18		1.50	
1980-1990	3.10	3.46	3.30	2.86		7.13		1.86	

* Projections prepared by PPSP.
Peak demand figures are for the winter beginning in designated year.
Energy sales figures exclude sales for resale and sales to Easton. Peak demand figures include the portion of Easton peak served by DP&L generation. The 1990 peak load projection is reduced by 22 megawatts to account for acquisition of capacity by the Old Dominion Electric Cooperative.

Table I-34

Historic Energy Sales, Peak Demand And
Generating Capacity For The Potomac Electric Power Company (Total System)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin %
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	1,978	5,661	7,639	2,123	1,249	2,363	11.3%
1970	2,932	8,251	11,183	2,908	1,813	3,708	27.5
1971	3,038	8,696	11,734	3,045	1,919	4,529	39.9
1972	3,122	9,069	12,190	3,479	1,990	4,454	28.0
1973	3,529	9,704	13,233	3,680	2,159	4,721	28.3
1974	3,304	8,885	12,189	3,502	2,012	4,933	40.9
1975	3,399	9,322	12,722	3,623	2,145	5,190	43.3
1976	3,485	4,603	13,088	3,500	2,334	5,010	43.1
1977	3,617	10,030	13,647	3,857	2,508	5,013	30.0
1978	3,761	10,473	14,234	3,714	2,682	5,003	34.7
1979	3,907	10,821	14,729	3,804	2,691	4,990	31.2
1980	4,026	11,425	15,451	4,142	--	4,999	20.7
			Annual Average Rates of Growth				
1966-1970	10.34%	9.88%	10.01%	8.18%	9.78%	11.92%	
1970-1975	3.00	2.47	2.61	4.49	3.42	6.96	
1975-1980	3.44	4.16	3.96	2.71	-	-0.74	
1966-1980	5.21	5.14	5.16	4.89	-	5.50	

Peak demand figures are for the winter beginning in designated year. Data exclude energy retail sales in Virginia and sales to SMECO, but include Virginia and SMECO loads at the time of system peak.

Table I-35

Projected Energy Sales, Peak Demand And
Generating Capacity For The Potomac Electric Power Company (Total System)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve Margin(%)	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)		Summer Peak (MW)	R.M.(%)
1981	4,232	11,276	15,508	4,242		4,999	17.9%	4,152	20.4%
1982	4,404	11,424	15,828	4,284		4,996	16.6	3,956	26.3
1983	4,590	11,572	16,162	4,322		5,322	23.1	4,000	33.1
1984	4,790	11,704	16,494	4,358		5,322	22.1	4,058	31.2
1985	5,000	11,824	16,824	4,393		5,322	21.2	4,105	29.7
1986	5,235	11,853	17,088	4,420		5,322	20.4	4,153	28.2
1987	5,484	11,962	17,446	4,453		5,322	19.5	4,208	26.5
1988	5,746	12,072	17,818	4,486		5,322	18.6	4,259	25.0
1989	6,020	12,184	18,204	4,520		5,322	17.7	4,302	23.7
1990	6,308	12,297	18,599	4,554		5,148	13.0	4,355	18.2
			Annual Average Rates of Growth						
1980-1985	4.43%	0.70%	1.72%	1.18%		1.26%		-0.18%	
1985-1990	4.76	0.79	2.03	0.72		-0.65		1.19	
1980-1990	4.60	0.74	1.87	0.95		0.29		0.50	

* Projections prepared by PPSP.
Energy sales exclude retail sales in Virginia and sales to SMECO, but include Virginia and SMECO loads at the time of the system peak.

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CHAPTER II

POWER SUPPLY IN THE STATE OF MARYLAND

This chapter describes trends and issues relating to the supply of electric power by Maryland utilities. To place this subject in proper perspective, national and Maryland overall energy production trends are first examined. Next, the generation profiles and capacity expansion plans of each of the four major Maryland utility systems are presented in detail. The third section of this chapter concerns generating capacity expansion planning. An overview of the basic principles, methods and problems of generating planning is provided. The fourth section contains a discussion of some of the more important unconventional generation sources such as cogeneration, wind energy and small-scale hydroelectricity. This chapter concludes with a list of definitions of terms commonly used in the electric utility industry.

A. Nationwide Energy Production Trends

Primary energy supply in the U.S. grew steadily during the 1950's, 1960's and early 1970's. The increasing demand for energy was met principally by increases in natural gas and oil production and by higher levels of imports. As a consequence of the Arab oil embargo of 1973 and the subsequent increases in petroleum prices, the supply of primary energy shifted towards greater reliance on coal and nuclear energy. This shift represents an adjustment to the significantly higher price of petroleum, both absolutely and relative to other fuels, at the end of the 1970's compared to the pre-embargo years.

As shown in Table II-1, domestic production and net imports of oil and natural gas accounted for approximately 78 percent of total primary energy supply in 1973, while coal and nuclear energy combined represented 19 percent of supply. Hydro, solar and geothermal accounted for the remaining 3 percent. The most recent Department of Energy forecasts for 1985 indicate that the portion of total primary energy supply from coal and nuclear energy will rise to 33 percent, while domestic and net imports of oil and natural gas will decline to 62 percent.[1] This represents a substantial shift to coal and nuclear (1).

While higher prices for oil and natural gas have induced producers to increase exploration and to employ enhanced recovery techniques, physical returns to drilling are declining. Figure II-1 indicates a sharp increase in drilling activity throughout the forecast period, though less pronounced than the increase which occurred in the 1970's. The number of feet drilled is expected to approximately triple between 1971, a year of relatively low drilling activity, and 1995. In spite of the expected increase in drilling activity, the projected barrel-per-day of output over that period shows very little change (see Figure II-2).

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[1] Percentages are based on the Btu content of the primary energy sources.

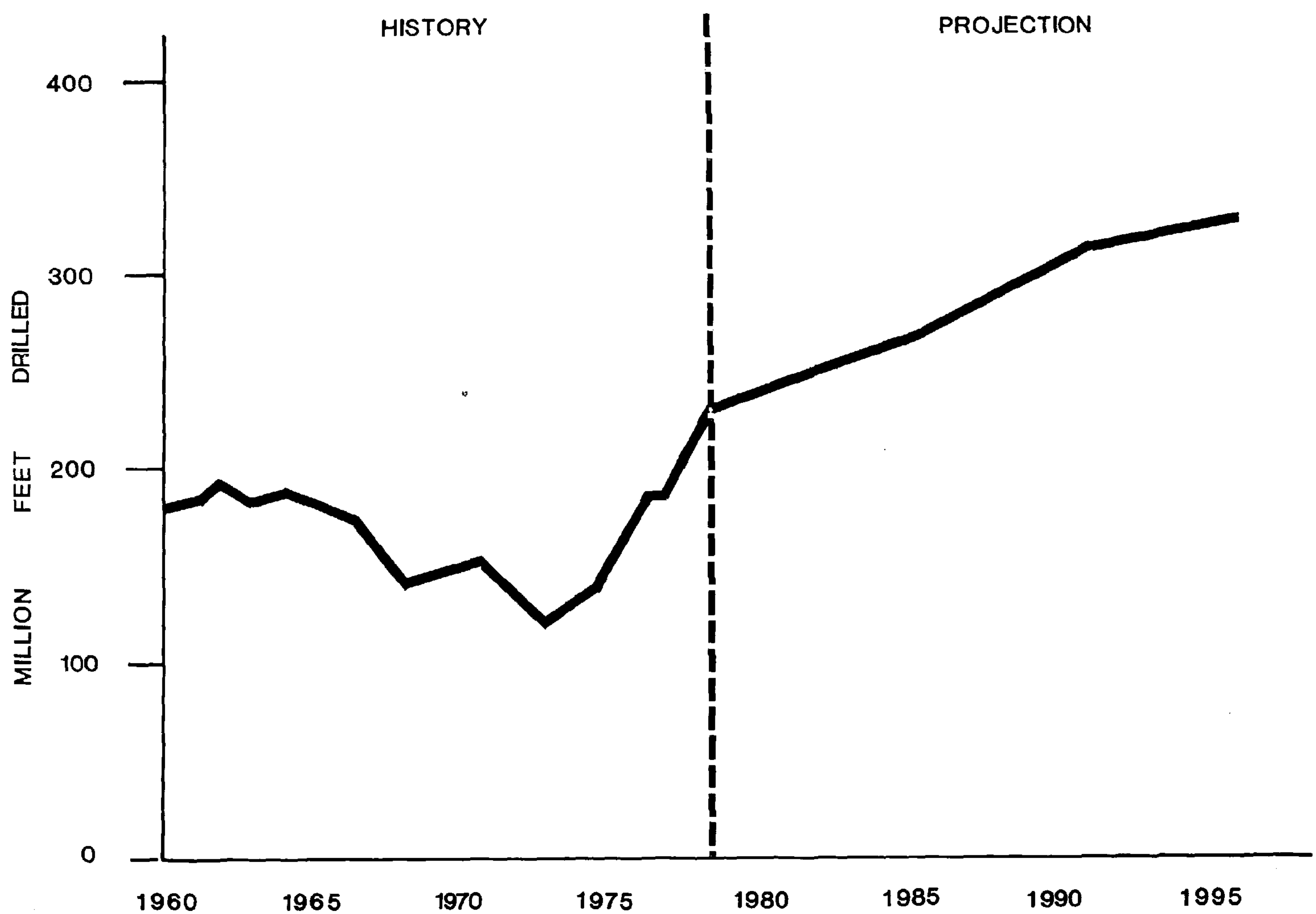

Fig. II-1. U.S. Oil and Gas Well Drilling, 1960-1995.

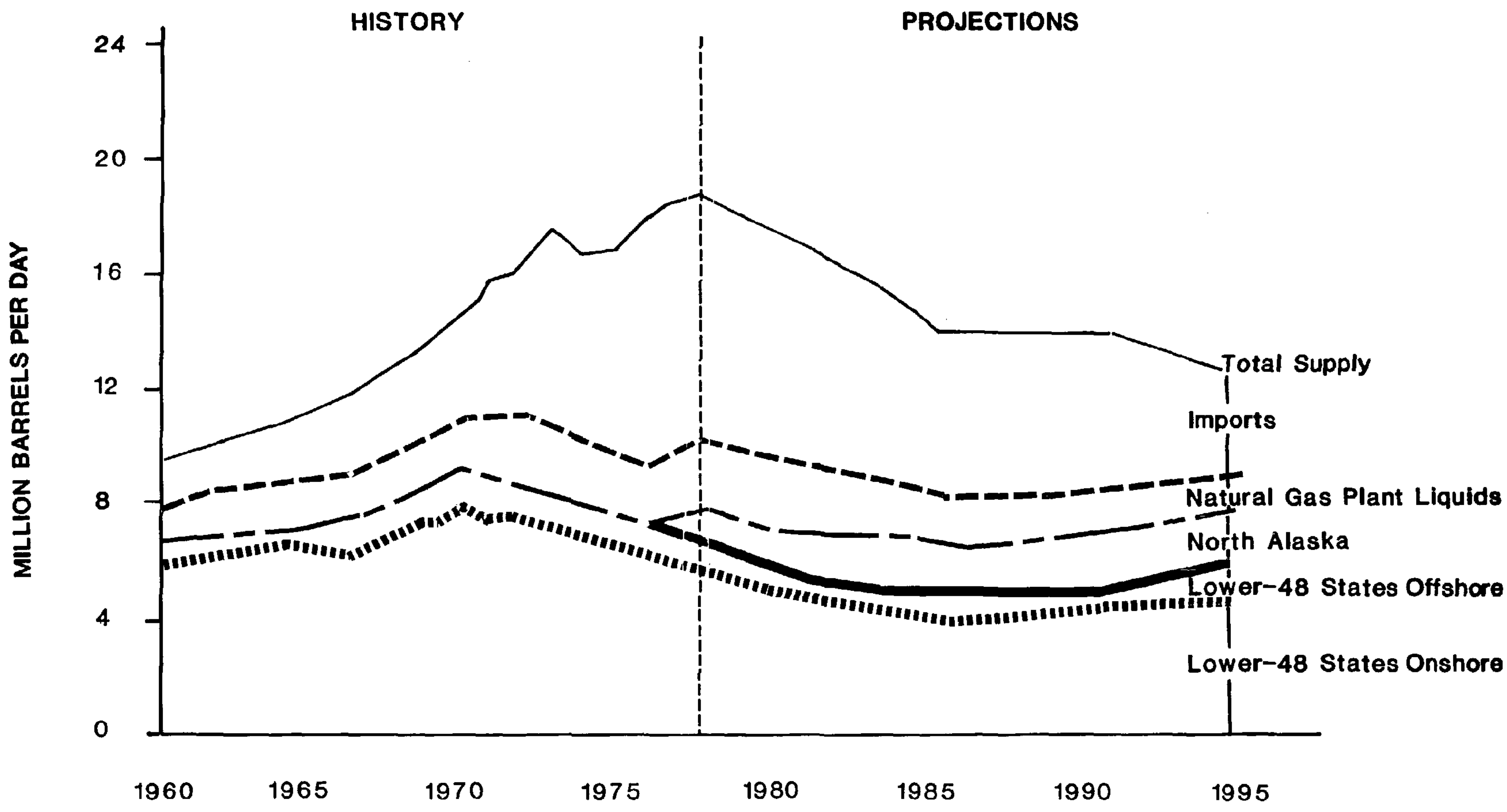

Fig. II-2. U.S. Petroleum Liquids Supply by Source, 1960-1995.

The pattern of electric power supply in the U.S. reflects both the conditions in primary energy markets (including the slower growth in demand for electricity) and changes in the regulatory environment. The Power Plant and Industrial Fuel Use Act of 1978 (Public Law 95-620) prohibits the use of oil or natural gas as a primary fuel for new electric generating units and for existing units which can be converted from oil to coal.[1] The Act also restricts use of natural gas in existing power plants. Unless a utility submits a plan for reducing its consumption of natural gas by 1990 to 20 percent of the natural gas consumed in 1976, it is prohibited from using any natural gas after January 1990. Additionally, the proportion of natural gas consumed by an electric utility in any year prior to 1990 cannot exceed the average proportion consumed in the period from 1974 through 1976.

While exemptions from the Fuel Use Act guidelines may be granted for reasons of excessive cost of converting from oil to coal, fuel availability, or environmental considerations, the combined effects of the Fuel Use Act and higher oil and natural gas prices are clear: the future fuel mix of electric utilities will emphasize coal and nuclear more heavily than has been true in the past. The combined percentage of coal and nuclear fuel used by electric utilities is expected to rise from 48.2 percent in 1973 to 74.2 percent in 1985 and to 80.6 percent in 1990 according to EIA data (see Table II-2). National projections of electric utility generating capacity reveal a similar trend of increasing reliance on coal and nuclear and diminishing reliance on oil and natural gas (see Table II-3).

Projections for the composition of supply of electric power by Maryland utilities broadly follow the national trends though certain differences are apparent. As shown in Table II-5, 57 percent of the current generating capacity is coal-fired and 31 percent oil-fired. Current plans of the Maryland utilities will result in 61.6 percent of capacity being coal-fired by 1990, while oil-fired capacity falls to 23.7 percent.

While Maryland plans reflect national trends towards coal-fired capacity and away from oil-fired capacity, Maryland is currently more oil dependent than the nation as a whole and is expected to remain so through the end of this decade. Although Maryland's generation mix differs somewhat from the nationwide average, it is fairly typical of the Northeast region of the country. This region has neither the convenient access to coal nor the great hydroelectric resources found in other regions of the country. In addition, many units originally designed to burn coal were converted to oil for environmental reasons during the 1960's. For all of these reasons, the Northeast (including Maryland) became more oil dependent than the rest of the nation.

In addition to inducing a shift to coal, higher oil and gas prices will encourage the expansion of hydroelectric and nuclear capacity. At the national level, hydroelectric generating capacity is forecasted to increase approximately 35 percent between 1978 and 1990.[2] Hydroelectric capacity owned by Maryland utilities is expected to increase by over 600 percent during the 1980's and will account for 5.5 percent of 1990 generating capacity compared with 1.1 percent in 1980.

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[1] The Act also provides exemptions for peaking units, such as combustion turbines.

[2] Based upon EIA middle oil price scenario.

Table II-1

U.S. Primary Energy Supply 1965-1995[a]
Domestic Supply And Net Imports
(Quadrillion Btu's)

Year	Oil	Natural Gas	Coal	Nuclear	Other[b]	Total
1965	23.4	16.2	12.0	$<$0.1	2.1	53.7
1973	35.1	23.2	13.0	0.9	2.9	75.0
1978	37.8	20.4	14.1	3.0	3.0	78.4
1985	30.5	18.6	20.6	5.6	3.4	78.7
1990	30.8	17.0	27.6	8.0	3.6	87.0
1995	29.0	16.4	35.0	9.1	4.2	93.7

(a) Forecasts based on EIA middle price scenario.

(b) Other includes hydroelectric, solar, and geothermal.

Source: (1).

Table II-2

Electricity Fuel Consumption, 1965-1995
(Quadrillion Btu's)

Fuel	1965		1973		1978		1985		1990		1995	
	Quads	%	Quads	%	Quads	%	Quads	%	Quads	%	Quads	%
Fossil Fuels:												
Oil	0.8	7.2%	3.6	18.1%	3.8	16.3%	1.6	5.7%	2.1	6.4%	0.8	2.1%
Natural Gas	2.4	21.6	3.7	18.6	3.3	14.2	2.2	7.8	0.6	1.8	0	0
Coal	5.8	52.3	8.7	43.7	10.3	44.2	15.3	54.3	18.3	56.1	23.4	62.4
Subtotal	9.0	81.1	16.1	80.9	17.4	74.7	19.1	67.7	21.0	64.4	24.2	64.5
Nuclear	(a)		0.9	4.5	3.0	12.9	5.6	19.9	8.0	24.5	9.1	24.3
Hydroelectric	2.0	18.0	2.8	14.1	2.9	12.5	3.2	11.4	3.2	9.8	3.3	8.8
New Technologies (b)	(a)		(a)		0.1	0.4	0.3	1.1	0.4	1.2	0.8	2.1
Total Consumption	11.1		19.9		23.3		28.2		32.6		37.5	
Total Generation	3.6		6.4		7.5		9.0		10.6		12.5	

(a) Less than 0.05 quadrillion Btu.

(b) New technologies' historical data consist of geothermal and wood waste technologies. The projections include the following renewable resources: geothermal, wind, solar thermal, solar photovoltaics, biomass, and ocean thermal.

Source: (1).

Table II-3

Electric Utility Generation Capacity And Reserve Margins 1965-1995
(Millions Of Kilowatts)

	1965	1973	1978	1985[c]	1990[c]	1995[c]
Fossil Steam						
Oil	NA	NA	NA	77.0	92.0	82.0
Natural Gas	NA	NA	NA	69.0	48.0	56.0
Coal	NA	NA	NA	289.0	341.0	472.0
Subtotal	187.0	321.0	400.0	435.0	481.0	610.0
Nuclear	1.0	21.0	54.0	88.0	125.0	141.0
Hydroelectric	44.0	62.0	71.0	87.0	96.0	109.0
Combined Cycle	a	a	a	8.0	8.0	8.0
Combustion Turbine	5.0	38.0	55.0	64.0	73.0	80.0
New Technologies[b]	a	a	1.0	4.0	7.0	18.0
Total Capacity	236.0	442.0	579.0	686.0	790.0	966.0
Peak Demand	186.0	344.0	408.0	483.0	568.0	670.0
Reserve Margin (percent)	26.7%	28.5%	41.8%	41.9%	39.2%	44.2%

[a] Less than 0.5 million kilowatts.
[b] New technologies include the following renewable resources: geothermal, wind, solar thermal, solar photovoltaics, biomass, and ocean thermal. New coal conversion processes are reported with coal.
[c] Projections based on EIA middle price scenario.

Source: (1).

Table II-4

Production Of Electricity By The Electric Utility Industry
By Type Of Energy Source 1960-1980
(Billion Kilowatt Hours)

Energy Source	1960		1965		1970		1975		1980*	
	10^9KWH	Percent	10^9KWH	Percent	10^9KWH	Percent	10^9KWH	Percent	10^9KWH	Percent
Coal	403	53.5%	571	54.1%	704	46.0%	853	44.5%	1161	50.8%
Petroleum	46	6.1	65	6.2	184	12.0	289	15.1	246	10.8
Natural Gas	158	21.0	222	21.0	373	24.3	300	15.6	346	15.1
Nuclear Power	1	0.1	4	0.4	22	1.4	173	9.0	251	11.0
Hydro Power	146	19.4	194	18.4	248	16.2	300	15.6	276	12.1
Other	-	-	-	-	0.1	0.1	3	0.2	0.6	0.3
Total	753		1055		1532		1918		2286	

* Estimate

Source: (2).

Table II-5

Electric Utility Generation
Capacity--Maryland Utility Systems
1980 AND 1990*
(Megawatts)

	1980		1990	
	MW/Percent		MW/Percent	
Oil	5,966	31.3%	5,799	23.7%
Coal	10,763	56.5	15,042	61.6
Natural Gas	246	1.3	246	1.0
Hydroelectric	211	1.1	1,339	5.5
Nuclear	1860	9.8	2,026	8.3
TOTAL	19,046		24,432	

* Based on Summer 1980 capacity; projections based on planned additions and retirements.

Source: (3).

Most of the increase in hydroelectric capacity is represented by the Allegheny Power System's decision to purchase a large part of the Bath County pumped storage project. Increased ownership in the Safe Harbor Facility by BG&E and several small scale hydro projects will also add to the total. Although this represents a significant increase in total hydroelectric capacity, this 5.5 percentage is well below the 12.2 percent national figure projected for 1990.

Similarly, nuclear-powered units are projected to account for approximately 8 percent of the Maryland utilities' generating capacity in 1990, while nuclear plants nationwide are forecasted to represent 16 percent of capacity. The absence of additional nuclear capacity from the generation expansion plans of Maryland utilities is due in large part to the slowdown in both recent and projected growth in the demand for electricity, proximity to coal supplies, and the need for relatively small size generating units, as well as economic conditions which have reduced the relative desirability of nuclear power. In order for a nuclear-powered generating plant to be economically attractive, it needs to be large enough to capture the benefits of scale economies. Typically, nuclear units which have gone into service in recent years have name-plate capacity ratings of approximately 900 megawatts or more. (Calvert Cliffs in Maryland includes two 810 MW units.) Because electric power demand growth for Maryland utilities is expected to be relatively slow over the next ten to fifteen years, a utility bringing on-line a 900-1100 megawatt unit must either carry substantial excess capacity for several years (if the plant is put into operation as soon as any of its capacity is required) or it must purchase power to meet its load (if the utility waits until demand is sufficient to absorb the additional capacity).[1]

In addition to this "lumpiness" problem, several other factors have dampened interest in nuclear power. First, the lead time required in bringing on-line a nuclear facility is in excess of ten years, with wide variability, making generation planning difficult. In addition to the planning difficulties, the potential economic advantage to the utilities of using nuclear power rather than coal as a fuel is substantially lessened by the ability of Maryland utilities to pass through to the consumer any increase in fuel prices on a monthly basis. Finally, both operating problems and regulatory delay have served to lessen the economic attractiveness of nuclear units.

The rate of growth of capacity for Maryland utilities over the next ten years is projected to be comparable to that of the nation as a whole. By 1990, capacity is expected to increase by 27 percent nationally and by 28 percent in Maryland. Since 1973, however, the proportionate increase in generating capacity by Maryland utilities has been significantly lower than that for the nation: only 28 percent compared to 39 percent nationally. The main reasons for this difference are the relatively slow economic growth since 1973 in the service areas of Maryland utilities and the excess capacity which existed in the early part of this period and which was largely due to the dramatic decrease in the rate of growth in the demand for electricity since 1973 (see Chapter I).

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[1] Utilities have sometimes attempted to deal with this problem by either jointly owning the plant with other utilities or by short-term capacity sales, i.e., selling off some of the capacity of the plant during its early years of operation.

B. Generation Profiles Of Maryland Utilities

As described in Chapter I, almost all of the bulk power consumed in Maryland is provided by four major, privately-owned, integrated utilities: Potomac Electric Power Company, Baltimore Gas and Electric, Potomac Edison and Delmarva Power and Light. This section examines the present and future generating profiles of each of these four major utilities. The discussion describes the capacity expansion plans over the next ten years and evaluates the ability of each utility to meet its future loads by comparing forecasted loads with planned capacity additions. Trends in generating capacity mix are also discussed.

The discussion in this section is supplemented by data tables which summarize the capacity expansion plans and generating capacity profiles of the four major electric utilities. Table II-6 provides forecasted demands, capacity and reserve margins for each utility. Table II-7 presents a schedule of capacity changes on a unit by unit basis through the end of this century. The capacity profile (i.e., megawatts by fuel type) of each utility is shown for 1979 and for selected future years in Table II-8. Those figures are also presented in percentages in Table II-9. Finally, Table II-10 presents each Company's megawatt hour generation by fuel type for calendar 1980.

Baltimore Gas and Electric Company (BG&E)

BG&E, serving Baltimore City and all or portions of eight surrounding counties, had a total generating capacity of 5,010 megawatts in 1980 compared with a peak demand of 3,969 megawatts, leaving BG&E with a reserve margin of approximately 26 percent.[1] PPSP forecasts peak demand growth of 2.8 percent per year through 1990, and current plans call for an annual increase in generating capacity of 2.3 percent. On the basis of this forecast and expansion plan, BG&E will have adequate reserves through the end of this decade. Reserve margins exceed 25 percent in most years and never fall below 20 percent. (see Table II-6).

During the 1980's, BG&E plans to add two 620 mW coal-burning units at the Brandon Shores site, purchase power from a 40 megawatt municipal solid waste generating plant, and a 125 megawatt expansion of its Safe Harbor hydro capacity. The solid waste plant is scheduled to begin service in 1985, the Brandon Shores units are scheduled for 1984 and 1988, and the Safe Harbor addition is scheduled for Fall 1985. Five oil-fired units at the Westport Station which total 177 megawatts are scheduled for retirement during the 1984-1992 period. For the 1990's, BG&E plans to add 1400 megawatts of "baseload" capacity and 443 megawatts of pumped storage. One of the baseload plants will be an 800 megawatt coal-fired plant to begin service in 1992 at the Perryman site. The Company plans to retain 400 megawatts of the plant.

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[1] The industry usually accepts reserve margins of 15 to 25 percent as adequate for reliability purposes. Planned reserve margins differ for each utility.

Table II-6

Forecasted Peak Demand, Generating Capacity and Reserve Margins, 1980-1990[a] (megawatts)

	BG&E			DP&L			Pepco			APS [b]		
	Demand	Capacity	R.M.	Demand	Capacity	R.M.	Demand	Capacity	R.M.	Demand	Capacity	R.M.
1980	3,969	5,010	26.2%	1,529	2,008	31.3%	4,142	4,999	20.7%	5,564	7,568	36.0%
1981	3,897	5,025	29.0	1,506	2,219	47.3	4,242	4,999	17.9	5,552	7,587	36.7
1982	4,028	5,025	24.8	1,547	2,324	50.2	4,284	4,996	16.6	5,726	7,600	32.7
1983	4,162	5,025	20.7	1,594	2,167	36.0	4,322	5,322	23.1	5,910	7,600	28.6
1984	4,303	5,594	30.0	1,641	2,167	32.1	4,358	5,322	22.1	6,093	7,600	24.7
1985	4,447	5,634	26.7	1,694	2,217	30.9	4,393	5,322	21.2	6,264	8,020	27.4
1986	4,591	5,759	25.4	1,749	2,217	26.8	4,420	5,322	20.4	6,443	8,440	31.0
1987	4,741	5,701	20.3	1,808	2,177	20.4	4,453	5,322	19.5	6,626	8,440	27.4
1988	4,897	6,321	29.1	1,869	2,177	16.5	4,486	5,322	18.6	6,810	8,440	23.9
1989	5,091	6,321	24.2	1,934	2,177	12.6	4,520	5,322	17.7	7,000	9,070	29.6
1990	5,232	6,321	20.8	1,951	2,502	28.2	4,554	5,148	13.0	7,236	8,995	24.3

(a) Capacity figures are from the Company's latest generation plan. Peak demand figures are PPSP forecasts.

(b) Figures refer to peaks and installed capacity for winter beginning in designated year.

Source: Chapter I, Tables I-24 through I-35.

Table II - 7

Summary Of Capacity Changes Of Maryland Utilities[a] (Megawatts)

	Additions	Reductions
1981	+19 Miscellaneous Rerates (APS)	- 12 Kent (DP&L) - 4 Edge Moor 2, 3 & 4 (DP&L) - 2 Delaware City 3 (DP&L) -269 Benning 13 & Buzzard 1-6 Retirement (Pepco)
1982	+83 Salem 2 (DP&L) +22 Indian River Uprate (DP&L) +600 Chalk Point 4 (Pepco) +23 Pleasants 2 Uprate (APS)	- 10 Mitchell 3 Derate (APS) - 8 Chalk Point 1 & 2 Derate (Pepco)
1983	No additions	- 70 Edge Moor 1 Retirement (DP&L) - 15 Edge Moor 4 (DP&L) - 70 Edge Moor 2 Retirement (DP&L) - 2 Edge Moor 3 (DP&L) - 8 Chalk Point 1 & 2 Derate
1984	+620 Brandon Shores 1 (BG&E)	- 51 Westport 1, 13, 14 (BG&E)
1985	+50 Indian River 4 (DP&L) +420 Bath Project (APS) +40 Solid Waste (BG&E)	No reductions
1986	+125 Safe Harbor (BG&E) +420 Bath Project (APS)	- 40 Delaware City 3
1987	No additions	- 58 Westport 4 (BG&E)
1988	+620 Brandon Shores) 2 (BG&E)	No reductions

Table II - 7 (Continued)

Summary of Capacity Plans Of
Maryland Utilities
(Megawatts)

	Additions	Reductions
1989	+630 Lower Armstrong 1 (APS)	
1990	+500 Vienna 9 (DP&L)[a] + 42 CT's (DP&L)	- 42 Edge Moor 10, Madison St (DP&L) - 75 Retirements (APS) -174 Potomac River 1, 2 (Pepco)
1991	+630 Lower Armstrong 2 (APS)	- 75 Retirements (APS)
1992	+800 Perryman (BG&E)[c] +630 Lower Armstrong 3 (APS) + 51 CT's (DP&L)	- 68 Westport 4 (BG&E) - 51 Delaware City 10, Indian River 10, Vienna 10 (DP&L) - 75 Retirements
1993	+300 Coal Plant (Pepco)	No reductions
1994	+148 Pumped Storage (BG&E)	No reductions
1995	+295 Pumped Storage (BG&E) +400 Coal Unit (DP&L)	No reductions
1996	No additions	-80 Edge Moor 3 (DP&L)
1997	+400 Base Load (BG&E)	No reductions

Table II-7 (Continued)

Summary of Capacity Plans of
Maryland Utilities
(Megawatts)

	Additions	Reductions
1998	No additions +400 Coal Unit (DP&L)	-89 Indian River 1 (DP&L)
1999	+225 Pumped Storage (Pepco) +600 Base Load (BG&E)	No reductions
2000	No additions	No reductions

[a] APS plans only available through 1992.

[b] DP&L's share of Vienna 9 is 325 MW. The other shares are 125 MW to Atlantic City Electric and 50 MW to the Old Dominion Electric Cooperative.

[c] BG&E's share will be 400 MW.

Source: (4), (5), (6), (7).

Table II-8
Generating Capacity Of Maryland Utility Systems
By Fuel-Type 1979-1991
(Megawatts)

	Pepco	DP&L[a]	APS	BG&E	Other[b] Md.	Total[c]
1979						
Oil/Gas	1,986	1,285	486	2,371	31	6,159
Coal	3,013	793	6,449	852	-	11,107
Nuclear	-	237	-	1,635	-	1,872
Hydro	-	-	62	152	950	1,164
Total	4,999	2,315	6,997	5,010	981	20,302
1981						
Oil/Gas	1,986	1,189	446	2,371	31	6,023
Coal	3,013	815	7,079	852	-	11,759
Nuclear	-	320	-	1,650	-	1,970
Hydro	-	-	62	152	950	1,164
Total	4,999	2,324	7,587	5,025	981	20,916
1986						
Oil/Gas	2,317	760	446	1,936	31	5,490
Coal	3,005	1,097	7,092	1,856	-	13,050
Nuclear	-	320	-	1,650	-	1,970
Hydro	-	-	902	277	950	2,129
Total	5,322	2,177	8,440	5,719	981	22,639
1991						
Oil/Gas	2,317	760	296	1,878	31	5,282
Coal	2,831	1,422	8,352	2,476	-	15,081
Nuclear	-	320	-	1,650	-	1,970
Hydro	-	-	902	277	950	2,129
Total	5,148	2,502	9,550	6,281	981	24,462

(a) DP&L figures are for 1980, 1982, 1987 and 1992 rather than indicated years.

(b) Includes oil-burning units at Hagerstown, Md. and hydro units at Deep Creek Lake and Conowingo.

(c) Table excludes generating capacity of Easton, Maryland; Dover, Delaware; and a 40 megawatt municipal solid waste unit supplying the BG&E system.

Source: (4), (5), (6), (7).

Table II-9

Generating Capacity Of Maryland Utility Systems
By Fuel-type 1979-1991
(percent)

	Pepco	DP&L	APS	BG&E	Total
1979					
Oil/Gas	39.7%	55.5%	7.0%	47.3%	30.3%
Coal	60.3	34.3	92.2	17.0	54.7
Nuclear	-	10.2	-	32.6	9.2
Hydro	-	-	0.9	3.0	5.7
1981					
Oil/Gas	39.7	51.2	5.9	47.2	28.8
Coal	60.3	35.1	93.3	17.0	56.2
Nuclear	-	13.8	-	32.8	9.4
Hydro	-	-	0.8	3.0	5.6
1986					
Oil/Gas	43.5	34.9	5.3	33.9	24.3
Coal	56.5	50.4	84.0	32.5	57.6
Nuclear	-	14.7	-	28.9	8.7
Hydro	-	-	10.7	4.8	9.4
1991					
Oil/Gas	45.0	30.4	3.1	29.9	21.6
Coal	55.0	56.8	87.5	39.4	61.7
Nuclear	-	12.8	-	26.3	8.1
Hydro	-	-	9.5	4.4	8.7

Source: Table II-8.

Table II-10

1980 Generation Profile Of The Maryland Utilities

Generation (Thousands MWh)

	Pepco	BG&E	DP&L*	APS	Total
Oil/Gas	1,983	3,361	4,051	103	9,498
Coal	16,095	5,167	2,971	34,645	58,878
Hydro	-	436	-	193	629
Nuclear	-	10,947	1,286	-	12,233
Total	18,078	19,911	8,308	34,941	81,238

Percent

	Pepco	BG&E	DP&L*	APS	Total
Oil/Gas	11.0%	16.9%	48.8%	0.3%	11.7%
Coal	89.0	26.0	35.8	99.2	72.5
Hydro	-	2.2	-	0.5	0.8
Nuclear	-	55.0	15.4	-	15.1

* Generation from Delaware City 1, 2 and Atlantic City Electric's share of Indian River 4 have been subtracted from the totals.

Source: (4), (5), (6), (7).

Currently, BG&E's capacity profile is dominated by nuclear and oil. Coal comprises only 17 percent of the total compared to 33 percent for nuclear and 47 percent for gas and oil. Over the next ten years oil capacity will decline, nuclear will not change, and coal capacity will increase substantially. However, as shown in Table II-8 and II-9, oil and gas will still provide more than a third of BG&E's capacity in 1991.

In evaluating the power supply profile of an electric utility system, it is important to recognize generation by fuel type as well as capacity by fuel type. This is because not all generating units on a utility system run for the same amount of time. With some minor exceptions, all four utilities operate on an economy basis, meaning that the units which are most inexpensive to operate are run as much as possible, and the units which are more expensive to operate are run only when required to serve loads.[1] BG&E provides an excellent example of economy operation. The Calvert Cliffs nuclear units account for less than a third of BG&E's capacity, but they accounted for more than half of the Company's power generation in 1980. Oil and gas represented about 47 percent of BG&E's capacity in 1980, but less than 20 percent of the Company's power generation. Thus, BG&E is not nearly as oil dependent as the capacity figures might suggest.

Delmarva Power and Light Company (DP&L)

DP&L provides either directly or indirectly more than 90 percent of the electric power consumed on the Delmarva Peninsula.[2] For purposes of planning and operation, DP&L functions as a completely integrated system. The description which follows, therefore, examines the DP&L service area in its entirety rather than artificially isolating the Maryland portion, which accounts for only approximately one-fourth of DP&L's systemwide sales.

All of the municipal and rural electric cooperative utilities on the Delmarva Peninsula are integrated with DP&L. However, the data presented in Tables II-6 through II-10 exclude the Dover, Delaware and Easton, Maryland municipal systems (the only other systems on the Peninsula generating significant amounts of power) since DP&L does not routinely report Group figures to the Maryland Public Service Commission. Those tables also exclude the Getty refinery load and the generating units dedicated to those loads.

The DP&L Group, which includes the Dover and Easton systems, had a total generating capacity of 2,533 megawatts in 1981. DP&L plans to increase capacity by 8.7 percent by 1991. During the 1980's, DP&L will replace much of its oil-fired capacity with coal and a small amount of nuclear. The principal additions to capacity in the 1980's are two coal-fired plants -- Indian River 4, which began operation in late 1980, is a 400 megawatt power plant[3], and the

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[1] Utilities sometimes run their high cost plants to take advantage of opportunities to sell power to a power pool. The pool settlements procedure more than reimburses them for the cost of doing so.

[2] The Peninsula consists of the Maryland Eastern Shore counties, the State of Delaware, and the two Virginia counties on the Eastern Shore.

[3] Atlantic City Electric Company will lease 50 megawatts from the Indian River plant until 1985.

and the proposed Vienna 9, scheduled to come on-line in 1990, has a planned capacity of 500 megawatts.[1] DP&L will receive 83 megawatts of capacity in 1981 from the Salem 2 nuclear plant. Edge Moor 3 and 4 (combined capacity 249 megawatts) will be converted from oil-fired to coal-fired in 1982 and 1983. Edge Moor 1 and 2, oil-fired units with a combined generating capacity of 140 megawatts, will be retired during the 1980's.

Between 1980 and 1990, peak demand is forecasted to grow at an average annual compount rate of 2.5 percent, compared with a 2.2 percent rate of growth for capacity. While DP&L's peak demand is expected to grow more rapidly than capacity, DP&L is expected to face high reserve margins during the early portion of the 1980's. Reserve margins are expected to exceed 25 percent through the mid-1980's but will drop below 20 percent during the late 1980's until Vienna 9 comes on-line in 1990.[2]

DP&L has designed its generation plan to move very rapidly away from its very heavy oil dependence. In 1980, more than half of the DP&L Group capacity was oil-fired, with coal accounting for only about one-third. By 1990, oil capacity will fall to 30 percent, and coal capacity will rise to 57 percent. Thus, a dramatic reversal will take place within a decade if the Company's plan is implemented.

The Company is currently seeking a license from the Maryland Public Service Commission for a 500 megawatt plant to be located at its existing Vienna, Maryland site (Maryland PSC Case No. 7222). Although DP&L now intends to begin operation in 1990, the Company originally intended to bring Vienna 9 on-line in 1987. That date would have been in advance of when the capacity would have been needed for reliability purposes according to the PPSP load forecast. However, a PPSP study demonstrated that oil savings from the operation of the plant make the 1987 on-line date economically attractive (9). This result is due to the large disparity between the per Btu price of oil and coal.

Like BG&E, the DP&L Group is operated on an economy dispatch basis -- generating units are dispatched in merit order on the basis of their relative operating costs. Although nearly 65 percent of the Company's capacity in 1980 was oil, only 51 percent of its power was generated from burning oil in 1980.[3] The tendency to minimize the usage of oil by instead operating the cheaper to operate coal and nuclear facilities is illustrated in the detailed generation data provided in PPSP's annual report on the long run generation plans of Maryland utilities (10). As the data in that report show, the coal burning facilities have dramatically higher capacity factors[4] than do the oil burning plants.

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[1] DP&L will maintain ownership of 325 megawatts, 50 megawatts will be owned by three rural co-ops that are presently wholesale customers of DP&L, and 125 megawatts will be owned by Atlantic City Electric.

[2] DP&L considers 16 percent an adequate reserve margin.

[3] The capacity percentage figure excludes Indian River 4 which did not begin service until October 1980.

[4] A capacity factor is defined as total electric energy generated by a plant during some time interval as a percentage of the total amount of energy the unit is capable of generating. For purposes of comparison, 1980 capacity factors have been adjusted for planned and forced outages of each unit.

The Allegheny Power System (APS)

APS is a predominantly coal-fired utility. This is not surprising given the fact that its service territory is one of this nation's most important coal mining regions. Given the fact that transportation represents a very large percentage of the total cost of coal for most utilities, APS' proximity to that fuel has made coal-fired generation particularly attractive. Currently, more than 90 percent of the system's capacity is coal-fired. In addition, APS has about 450 megawatts of oil generation and a small amount of hydro capacity.

APS plans to add nearly 2,100 megawatts of generating capacity between now and 1991 from two large projects. APS has announced its intention to participate in a joint venture with Virginia Electric Power Company (VEPCO) to construct a hydroelectric pumped storage facility in Bath County, Virginia. When completed, this project will be the world's largest pumped storage facility.[1] APS intends to purchase (and/or lease), subject to regulatory approval, either 40 or 50 percent of the total 2,100 megawatts of the plant. APS' current generation plan indicates 420 megawatts in 1985 and an additional 420 megawatts in 1986, but it may ultimately add as much as 1,050 megawatts.

The other major facility which APS lists in its generation plan is the Lower Armstrong Station, which will consist of three 630 megawatt coal-fired units. The three units are scheduled to begin service in 1989, 1991, and 1992. Some initial design work and a draft environmental impact statement have been completed. However, APS suspended work in 1978 on the project, indicating that its financial condition and expectations concerning future rate treatment prevent it from undertaking the project (11). In order that the first Lower Armstrong unit meet its planned in-service date of 1989, work must resume within the next year. Thus, if the suspension continues much longer, the Company will be forced to alter its generation plan.

The APS decision to participate in the Bath Project was prompted by its inability to proceed with Davis, a proposed 1,000 megawatt pumped hydro plant which had been licensed several years ago by the Federal Energy Regulatory Commission (FERC). The FERC license has been challenged in Federal Courts. After receiving the FERC license, APS was refused a dredge and fill permit for Davis by the Army Corps of Engineers. The permit dispute is currently under litigation, but APS has eliminated Davis from its current ten year plan. However, should it succeed in obtaining needed approval, APS would consider constructing Davis in the 1990's after completion of Lower Armstrong.

APS has also included in its plans some unspecified retirements over the 1990 to 1992 periods which amount to 225 megawatts of capacity.

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[1] Pumped storage hydro involves pumping water from a lower reservoir to a higher reservoir during the off-peak period and allowing that water to flow back into the lower reservoir and generate power during the peak period. The facility creates no additional electricity because the energy required for pumping exceeds the energy generated. However, it is able to shift energy from the off-peak to the peak period, and thereby make energy available when most needed.

APS' current capacity plan, when compared to the PPSP load forecast, indicates a pattern similar to that of DP&L (see Table II-6). Reserve margins are rather high in the early part of the 1980's and gradually decline thereafter.[1] After the early 1980's reserves will range between approximately 25-30 percent. Because of its relatively high system load factor, APS believes that its optimal reserve margin should be approximately 23 to 27 percent. Thus, APS' generation plan appears to be adequate and only requires carrying excess reserves in the early part of the 1980's.

That evaluation assumes that APS' current generation plan is built as scheduled. The Lower Armstrong units cannot be built as scheduled unless progress is resumed in the very near future. On the basis of existing forecasts, significant further delays would lead to an unreliable system by the early 1990's.

The Potomac Electric Power Company (Pepco)

Pepco currently has 4,999 megawatts of generating capacity, approximately 40 percent of which burns oil and the remainder burns coal. It currently lacks, and has no plans to add, hydroelectric or nuclear capacity. Pepco capacity expansion plans are rather modest, largely because the Company's system load is growing so slowly: Pepco is predicting annual load growth of approximately one percent. The nearly completed Chalk Point 4 oil-fired plant is expected to begin service in 1982. The Company is currently planning for an unspecified 300 megawatt coal unit in 1993 and is considering an underground pumped storage facility for the late 1990's. Mixed in with these capacity additions are several retirements of some of the Company's older, oil-fired capacity.

Despite the planned retirements, Pepco's percentage of oil capacity will increase over time. Pepco is the only Maryland utility expected to experience such an increase. This situation will occur for two reasons. First, the Chalk Point 4 unit, which will add 600 megawatts of oil capacity in 1982, was planned and designed before the industry began to switch away from oil capacity so decidedly. Second, the next capacity addition is not scheduled to occur until 1993, and that addition is only half the size of Chalk Point 4. Thus, Pepco's generation plan after 1982 provides little opportunity to replace oil.

Like the other Maryland utilities, Pepco dispatches its generating units on an economy, cost-minimizing basis. The Company, therefore, attempts to maximize the operation of its coal plants and to minimize the operation of its oil plants. Consequently, although oil represents about 40 percent of the Company's capacity, it accounted for only 11 percent of total power production in 1980.

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[1] The reserve margins for the first half of the 1980's are actually greater than shown in Table II-6 (which includes only installed capacity) because APS maintains a diversity exchange arrangement with Vepco. Under this arrangement APS supplies 300 megawatts to Vepco in the summer in exchange for the same amount of power in the winter. This arrangement will run until 1985.

Pepco's level of reserves is barely adequate at the present time. However, with the imminent addition of Chalk Point 4, Pepco's reserves should be adequate until the early 1990's if the present forecasts are correct. To some extent the Company can modify the level of reserves by altering planned retirement dates of its older capacity. However, current forecasts call for load growth of roughly one percent per year. If loads were actually to grow at the rate of just under three percent forecast by APS and the DP&L systems, Pepco would experience deficient reserves several years in advance of its next planned capacity addition. For that reason, the Pepco load growth warrants careful scrutiny.

C. Generation Planning

A generation expansion plan is the means by which a utility proposes to serve its expected future loads. A franchise monopoly held by a regulated utility carries with it an obligation to provide adequate and reliable service to all its "firm" customers, and capacity must be planned accordingly. At the same time, it is desirable that the utility provide reliable service at minimum long run cost. As a result, reliability and long-run cost minimization are the twin goals of system generation planning.

With these goals in mind, the generation planner must address the following fundamental questions:

- When should new capacity additions be scheduled to begin service?
- How large should those capacity additions be?
- What kind of generating capacity (i.e., technology and fuel type) should be added?
- How can and should power demands be managed to avoid expensive energy and/or capacity additions?

The question relating to the timing of new capacity is determined by the projected growth in loads on the system in conjunction with judgments concerning the appropriate reserve margin for the utility. Load forecasting and the subject of demand-side approaches to generation planning are discussed in detail in Chapter I. This section focuses on the economic principles normally employed in the selection of the least cost generating technology. The discussion also gives recognition to the various dynamic factors which may complicate the planning process and often limit the options available to the planner. This section concludes with a discussion of the conversion of oil-fired plants to coal.

Economic Principles of Generation Expansion Planning

Given forecasted loads and specified reliability standards (e.g., expressed as reserve margins), the planner determines when the system must add its next plant.[1] Having made the scheduling determination the planner must then select the least cost technology for the next unit. Conventional power plant technologies fall into three major categories -- baseload, cycling and peaking -- and five major fuel types -- nuclear, coal, hydro, oil and gas.[2]

The way in which a mix of these various plant types operate to serve a utility system's power demands can best be explained by reference to a typical daily load curve. That curve shows system demands at different times of the day. Load falls in the early morning hours and sharply rises throughout the day reaching a maximum in the late afternoon. Loads gradually subside during the evening. There is a certain minimum or "base" level of load which is exceeded at virtually every hour. This will be served by baseload units, which are large, very efficient generating units which run almost continuously. Because these units require long periods of time to be brought up to full throttle from a cold start, they can only run in a continuous mode. Typically, baseload units are coal or nuclear-fired and about 400 megawatts or larger.

Above the base or minimum load on the daily load curve, demand may change rapidly from hour to hour. There is a need for power plants on the system which can adjust their energy output to follow these changes in load. Cycling units have the capability of altering their output on short notice in response to expected load changes. The cost of this flexibility is some loss in energy efficiency as compared to the baseload units. Cycling units are usually steam plants, coal or oil-burning, and are somewhat smaller than baseload units. Hydro plants with reservoir storage can also be operated as cycling plants.

Finally, the very top of the load curve is served by peaking plants. Peaking plants are extremely expensive to operate, but are only run for short periods of time when power demands are near the maximum. Also, peaking plants are completely flexible and are capable of coming up to full load on very short notice (i.e., in minutes). Oil and gas burning combustion turbines are the most common type of peaking plant used in the industry. However, there

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[1] Because of the high cost of oil relative to other fuels, it is becoming increasingly common for utilities to schedule capacity additions in advance of load growth to displace oil-fired generation. Doing so reduces long-run system costs if the added fuel savings from accelerating the schedule more than offset the additional capital costs of carrying the "excess" capacity. A PPSP study concluded that this is likely to be the case for DP&L's proposed Vienna 9 plant (9).

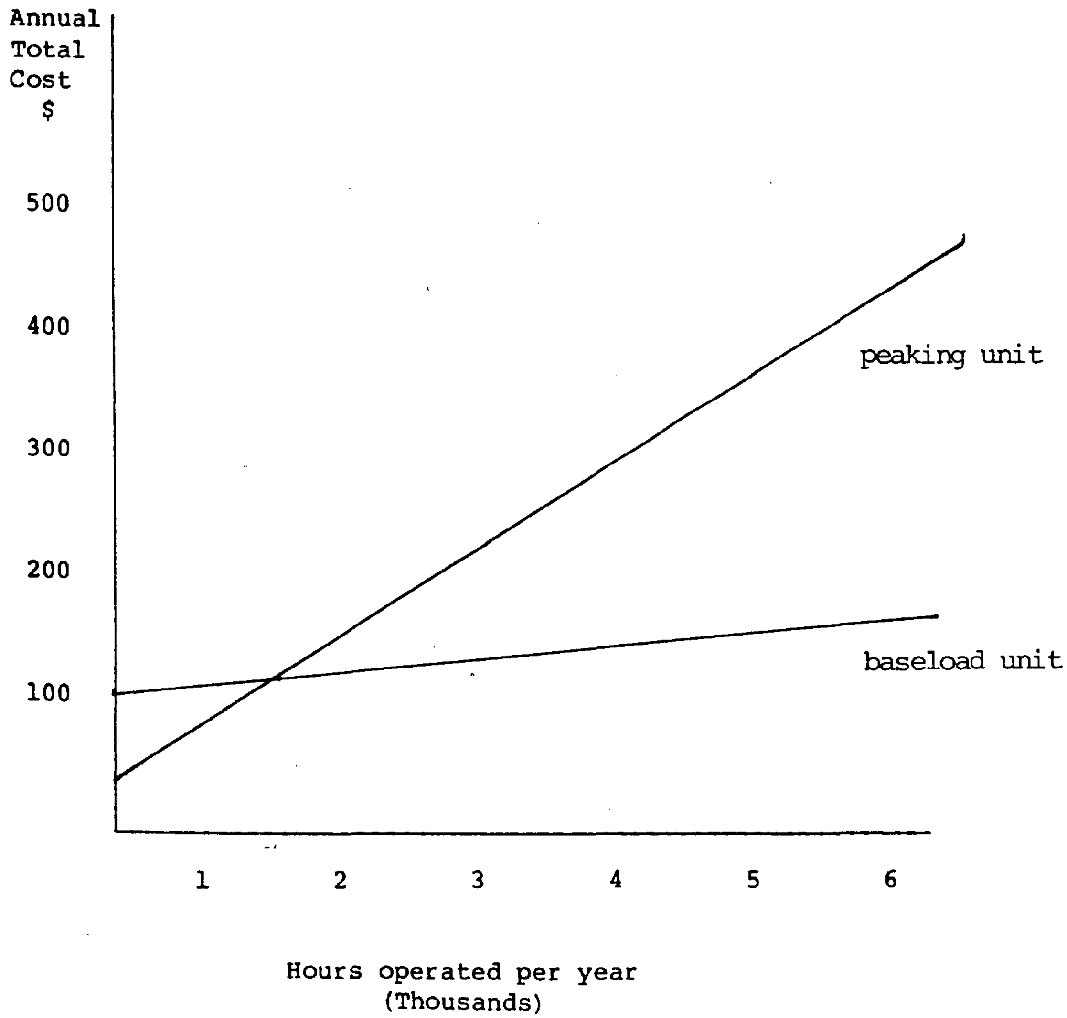
[2] The Fuel Use Act prohibits the use of gas or oil in new utility plants. However, it is possible to obtain exemptions for plants that will be operated as peaking units.

is also growing interest in pumped storage hydro both to serve peak loads and to function as cycling capacity.

Baseload, cycling and peaking plants have different operating characteristics, construction costs and lead time requirements. At one extreme, baseload plants are very expensive to construct and install on a per kW basis compared to smaller peaking plants. Offsetting that, baseload plants are capable of burning relatively inexpensive fuels (e.g., coal and uranium) and do so with relatively high efficiency. Thus, on a per kilowatt hour basis they are the most inexpensive plants to operate. At the other extreme peaking units are relatively inexpensive to construct per kW but are expensive to operate, largely because they typically burn oil or gas.

Thus, aside from operating characteristics, the choice of plant type is a matter of trading off capital and operating costs. For example, a typical baseload coal plant might cost $1,000 per kilowatt to construct and have an operating cost (i.e., fuel cost) of 1.5 cents per kilowatt hour. By comparison, a combustion turbine unit might cost roughly $200 per kilowatt to construct and 7 cents per kilowatt hour to operate. The selection of the type of capacity will ultimately depend upon the number of hours the plant must run. If the plant is expected to run a large number of hours, a baseload plant is clearly more economic. If the capacity is only required for a small number of hours, it is more economic to conserve capital costs and expend higher fuel costs.

The following diagram illustrates this trade-off on an annual basis for one kilowatt of capacity. A 10 percent annual carrying cost is assumed, translating the capital costs into $100 per kW per year for baseload and $20 per kW for a peaking unit.



The two lines indicate the total annual cost of carrying and operating both types of capacity at varying levels of usage. This diagram indicates that total costs are equal at roughly 1,500 hours of usage; for fewer hours of usage the peaking unit is less expensive, and for more hours of operation the baseload unit is less expensive. This simplified example, however, will overstate the attractiveness of the peaking unit if it is expected that oil will increase in price over time more rapidly than coal.

In order to select an optimal plant size and fuel type, it is necessary to compare generating costs in a manner which reasonably reflects the full range and complexity of relevant economic and engineering factors. The variable costs of bulk power supply over an appropriate time horizon (usually about 20 years) are often calculated by the use of a production costing simulation model. These models attempt to simulate the operation of a given power system by dispatching the utility's power plants to meet its forecasted loads. It is assumed (unless otherwise adjusted for) that plants will be dispatched on a merit basis so as to serve load in the most inexpensive way possible. The modeling takes into account numerous factors, including fuel costs over time, non-fuel operating and maintenance expenses, load growth, changes in load shape, unit maintenance requirements and forced outages.

After determining the variable costs of different generation capacity plans from the simulation model (and discounting those costs to the present), the fixed costs of the various generation plans must be considered. The fixed costs may be calculated as the additional revenue requirements over the time horizon of the alternative capacity addition plans (discounted to present value).[1] The sum of the variable and fixed cost revenue requirements is the total cost of a given plan. The plan providing the lowest total cost, assuming it satisfies the reliability criteria, is considered optimal.

The above discussion describes the straight-forward calculations used to determine the selection of the least-cost generation technology alternative. It is also important to recognize that the planner faces a multitude of complications and constraints. A partial list includes the following:

- Uncertainty -- The single most important planning decision relates to capacity addition timing. Unfortunately, the load forecasts which are relied upon tend to be highly uncertain. Similarly, the calculation of the cost-minimizing technology is based upon uncertain assumptions regarding future fuel prices, capital costs and so forth.

- Lead Time -- It now requires 10-12 years or longer to site, license and construct a new baseload power plant. Long lead times have the effect of reducing planning flexibility by limiting the feasible generation alternatives. For example, a firm may need new capacity sooner than it is capable of getting a new baseload unit on-line.

- Financial Capability -- Electric utilities do not have unlimited financial resources. The generation plan must therefore be consistent with the ability of the utility to raise the required investment capital. It is possible that financial limitations might force a utility to select a capacity expansion plan which does not minimize long-run costs.

- Regulatory Constraint -- Generation planning options are sometimes limited by regulatory constraints on power plant construction and operation. The inability of APS to obtain approval to construct the Davis pumped storage project is an example of such constraint. The restrictions in the Fuel Use Act represent a further restriction on the fuel type a power plant may be designed to burn.

Generation planning is clearly not a simple, straightforward exercise. It requires reconciling the economically most attractive plan with a long list of real world risks and problems which are beyond the direct control of the planner.

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[1] As in our simplified example, capital costs of alternative plants may be calculated by applying an appropriate annual carrying cost rate to the construction costs.

Coal Conversion

The price of oil in recent years has increased significantly and far more quickly than the price of coal. Prior to the 1973-74 Arab oil embargo, oil was viewed as an inexpensive, readily available and convenient fuel. Additionally, oil is a relatively clean fuel and does not require large investments in pollution abatement equipment. Consequently, the generation plans drawn up in the late 1950's, 1960's, and early 1970's relied heavily upon oil-fired power plants. It has been become evident since the embargo, however, that coal is generally more economical to use as a primary fuel in baseload generating units. Unfortunately, the replacement of oil-fired capacity with coal-fired capacity is complicated by the fact that the useful life of a generating unit is about 30 years. The long service life, coupled with the large initial capital investment associated with bringing on a new plant, tends to discourage replacement of oil-fired capacity far in advance of the originally envisaged retirement date.

A utility may, however, have the option of converting an oil-fired unit. Conversion of a generating unit specifically designed to burn oil into a coal-fired unit involves major alterations to the unit. However, many facilities were originally designed to burn coal and were later converted to oil. It is economically practical to reconvert many of these "coal-capable" units. Coal conversion is cost-effective only if the capital costs of conversion can be recovered over the remaining useful life of the generating unit by the savings (appropriately discounted) obtained by using coal as a primary fuel rather than the higher priced oil. This condition will be met if (1) the price of a unit of coal does not quickly increase to approach the price of an energy-equivalent amount of oil; and (2) if the useful life of the generating unit is sufficiently long. Clearly, if the cost of obtaining energy from coal is roughly equal to the cost of energy from oil, there is no compelling economic reason to convert to coal. Similarly, if the power plant under consideration can supply only a few remaining years of useful service, there will to be too few kilowatt hours generated in which to recoup the initial capital costs associated with the conversion.

The Energy Supply and Environmental Coordination Act of 1974 underscored the Federal Government's interest in shifting reliance from oil to coal and stipulated that coal-capable power plants must burn coal. In 1978, stricter standards were enacted and financial incentives were created to induce utilities to alter their fuel mix in favor of coal. The Power Plant and Industrial Fuel Use Act (1978) precludes the construction of large (baseload) oil and natural gas boilers by public utilities and industry[1], though certain exemptions may be granted by the U.S. Department of Energy if warranted by environmental or economic considerations, or site-specific limitations, such as insufficient space to achieve a coal-handling ability. The construction of oil-fired peaking units, however, may be permitted.

The Energy Tax Act (1978) provides financial incentives for coal conversion through a ten percent tax credit and accelerated depreciation. Not only are such tax credits unavailable for natural gas and oil-fired units, but they must be depreciated using the straight line method.

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[1] Boilers with a fuel heat input rate equal to or greater than 100 million Btu's per hour are considered large.

There are a number of technical and regulatory impediments to coal conversion. First, air quality regulations require desulfurization equipment to be installed if other than low sulfur coal is to be used.[1] The expense of desulfurization equipment may, in certain cases, be eliminated only by using more expensive low sulfur coal (see Chapter III). In non-attainment areas (where air quality standards are not met), pollution offsets may be required; that is, arrangements need to be made to reduce the emissions of the pollutant in question within the non-attainment area through reductions in emissions from other sources (see Chapter III).

Second, operation of a coal-fired unit requires more space than operation of an oil-fired unit of comparable capacity. Many stations lack the large area which is needed for coal storage. Also, waste material resulting from the burning of coal (e.g., fly ash), must be disposed (see Chapter VIII).

Third, when coal plants were originally converted to oil, many were replaced with boilers capable of burning only oil. Unless extensive alternations are undertaken, these units can only burn coal in the form of a coal/oil mixture -- a technology which is still in experimental stages. If the mix is more than 50 percent coal, it is considered by the U.S. Environmental Protection Agency (EPA) to be solid fuel, and federally mandated pollution control equipment for coal-burning stations must be installed. This creates a powerful disincentive to employ that fuel mix.

While the factors enumerated above serve to inhibit coal conversion, regulatory and economic considerations have made conversion an attractive option for several power plants owned by Maryland utilities. DP&L plans to convert the Edge Moor 3 and 4 facilities in 1982 and 1983 (249 megawatts), and BG&E is converting both its C.P. Crane facility (384 megawatts) and its two Brandon Shores plants (620 megawatts each) which are now under construction. No other utilities operating in the State currently have any coal conversion plans.

Coal conversion (to burn high sulfur coal) has been estimated at approximately $500 per kilowatt (1981 dollars). For example, at Delmarva's Edge Moor 3 and 4, the cost of conversion is estimated to be $74.6 million ($297/kW). DP&L plans to use expensive, low sulphur coal at the Edge Moor plants. The Company estimates that if it installs desulphurization equipment instead of using low sulphur coal at those plants, capital costs of coal conversion would be $175 to $200 per kW higher (12). Coal conversion often results in a slight reduction in generating capacity. In the case of Edge Moor 3 and 4, generating capacity is expected to decline by 5 megawatts for both units combined (2.0 percent), which is a cost that should be considered part of the coal conversion costs.

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[1] Western Maryland coal has a relatively high sulfur content.

D. Alternatives to Conventional Generation

Since 1973, the cost of generating electricity by conventional means has increased substantially. It has also become evident that much of our primary energy is supplied by unstable and unreliable sources. As a consequence of higher costs and an increased awareness of the need for a greater degree of energy independence, increased emphasis has been placed on the development and use of unconventional methods of electric generation to augment conventional sources. Both at the federal and state levels, financial incentives have been provided to induce residential, commercial, and industrial users to employ alternate sources of electricity.

Some of the more promising alternative generation sources are cogeneration, wind, solar, municipal solid waste, and small scale hydroelectric. Because of their current limitations, either due to technological considerations or their region-specific nature, this section does not examine such technologies as photovoltaics, ocean thermal energy conversion (OTEC), geothermal, or tidal power.

Legislation enacted 1981 by the Maryland General Assembly (Ch. 497) established the Maryland Energy Financing Administration (MEFA). MEFA was created to alleviate the problems of high initial cost and insufficient conventional financing of conservation and renewable resource equipment and installation in the industrial and commercial sectors. MEFA will be a self-supporting unit within the Department of Economic and Community Development, and is authorized to issue revenue bonds to finance low-interest loans for conservation, solar energy alcohol fuel production, geothermal, hydropower, cogeneration, synthetic fuel from coal, municipal solid waste, wood and wind projects (14).

In examining alternatives to conventional generation, special emphasis is given to their applicability in the State of Maryland and to the current Maryland experience and plans.

Municipal Solid Wastes

As an alternative to costly conventional fuels such as oil and coal, municipal solid wastes, which would otherwise be disposed of in landfills, are soon to be employed at several sites in Maryland. In addition to potential savings in fuel costs, generation using municipal solid wastes provides two other benefits. First, valuable landfill sites will be exhausted less quickly, thereby reducing the need for additional sites. Second, this technology provides a vehicle for the recycling of reusable wastes, such as glass and metals. The sorting of recyclable material is generally performed in conjunction with the sorting of usable energy-producing refuse.

The Northeast Maryland Waste Disposal Authority is currently in the final stages of replacing a large incineration unit in Baltimore with a waste-to-energy facility capable of burning 2,000 tons of solid waste per day. Electricity from the 40 megawatt unit will be sold to BG&E. Consideration is also being given to the future operation of two other units, one in Baltimore and the second in Harford County. The Harford County unit, which is to burn 750 tons of solid waste per day, would sell steam to Aberdeen Proving Grounds and a small amount of electricity to BG&E. The Baltimore unit will produce steam to be used in the drying of sewage sludge (13).

The Maryland Environmental Service Resource Recovery Facility at Baltimore produces refuse derived fuel (RDF), which has a higher Btu content than unprocessed waste. RDF, which can be used for combustion or as a sewage composting agent, was tested by BG&E at the Crane plant as a fuel supplement for high sulfur coal and was found to perform well (14).

The Federal government provides financial incentives for the use of municipal solid wastes in energy-producing activities through the Windfall Profit Tax Act (1980) and the Energy Security Act (1980). A ten percent tax credit is allowed for equipment designed to burn biomass fuel or used for converting biomass into synthetic solid fuel. Also, tax exempt Industrial Development Bonds may be used to finance facilities to produce electricity from solid wastes if the facility is owned and operated by a state or the Federal government. Subsidized loans, loan guarantees, and tax-exempt grants may also be obtained from the Federal government.

Solar

Solar energy systems are of two basic types: passive and active. Passive solar systems refer simply to devices used to permit sunshine to enter a structure or to exclude sunshine. Such devices include shutters, large window areas, southern exposures, window shades, etc. Active solar systems are based on the collection, storage, and use of solar energy. Typically, water (or air) is heated via solar collectors and circulated throughout the heating system of the building or used to heat domestic hot water.

Because sunshine is not available at night or during periods of inclement weather, active solar systems are generally equipped with thermal storage capability. While it is possible to construct an active solar system with sufficient storage to supply all the hot water or space heating requirements of a building, the cost is generally prohibitive and a back-up system is usually relied upon.

The primary application of active solar heating systems is for residential use. Nationally, in 1979, approximately 80 percent of solar collectors were delivered to residential end users and 60 percent of all collectors were used to heat swimming pools (14). Industrial and commercial application has not been widespread.

The costs and productivity of solar units vary widely and depend upon the geographic area, the type of solar system used, and the housing structure to which the system is affixed. A recent study conducted by Resources for the Future show that low-end estimates of solar costs make it competitive with electric resistance heat (15).

Purchase and installation costs for an active solar water heating system vary substantially. According to a recent survey, the average cost of purchase and installation in Maryland in 1979 was approximately $3,200, and repair and maintenance expenses for the solar facilities have been negligible. This study also estimates the pay back time of a solar water heating system to be approximately 6.5 years (16).

A number of different federal, state and local financial incentives make the installation of a solar system more attractive to the homeowner. The 1980 Windfall Profit Tax Act stipulates a 40 percent tax credit for investment in solar systems up to a maximum of $4,000 per household. The 1978 National Energy Conservation Act allows FHA to increase its limit on low interest loans by 20 percent. Additionally, the Energy Security Act (1980) allows for the establishment of a Solar Bank to administer loans for solar systems through HUD.

Maryland State solar legislation specifies that solar units cannot be used as a basis for increasing property assessments and allows local municipalities to grant tax credits for solar equipment. Harford and Anne Arundel Counties have established such property tax credits which appear to have stimulated considerable solar activity.

Small Scale Hydroelectricity

With the realization that the most economical of the large scale hydroelectric potential in the United States has already been fully exploited, interest in small scale hydro power has been increasing. Both large and small scale hydro (capacity less than 30 megawatts)[1] have been important components of the electric power industry since its inception.

There is considerable potential for expansion of small scale hydro in the State of Maryland. The Maryland Energy Administration estimates that the total underdeveloped hydroelectric potential in the State is 560 million kWh per year with an energy equivalence of 6.2 million Btu per year (14).

The construction of a small scale hydroelectric facility requires a license from the Federal Energy Regulatory Commission (FERC). Normally, the first step in this process is to obtain a preliminary permit which FERC routinely grants to the applicant for an 18-month to two-year period. This temporary permit allows the applicant the time to perform the necessary feasibility and environmental studies and during that time maintain exclusive rights to the site. Upon completion of the studies the permit holder may apply for the construction and operating license to be reviewed by FERC. Currently, five preliminary permits have been either applied for or obtained for small scale hydro facilities in Maryland.

Certain environmental and institutional impediments inhibit wide reliance on small scale hydro. Rights of access to the river, stream bed and stream banks need to be secured and permits for dam construction need to be acquired. Additionally, restrictions along certain reaches prohibit dam construction and initial capital costs are increased as a result of the required construction of fish ladders.

Federal initiatives aimed at using small scale hydro are contained in the Public Utilities Regulatory Policies Act of 1978, the Windfall Profit Tax Act of 1980, and the Energy Security Act of 1980. Incentives include tax credits, loans and loan guarantees, and grants for the development and construction of demonstration projects.

Wind Energy

The average wind speed in most areas of the State of Maryland ranges from 8 to 10 miles per hour, making wind an uneconomical energy source in most

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[1] U.S. Department of Energy definition from the Public Utilities Regulatory Policies Act of 1978.

parts of the State. An average wind speed of 12 miles per hour is generally required to make wind-powered energy an attractive alternative to conventional energy sources (14).

The Federal government has established financial incentives to foster increased investment in wind energy. A 40 percent tax credit is provided through 1985 for investment in wind energy equipment by the Windfall Profit Tax Act (1980).

Cogeneration

Cogeneration is a familiar though, to some extent, underexploited power source. Widespread use of cogeneration has been taking place in the industrialized European nations for many years, and it has enjoyed some limited success in this country. Because of its efficiencies, proponents believe that the potential exists to radically expand its usage.

The term cogeneration has been used by engineers to describe a process whereby electricity and process heat in some form (e.g., process steam) are simultaneously produced. It may arise from a situation where the primary purpose of consuming energy is to produce electricity, and waste heat is produced. The firm may then find a productive use for that waste heat. Alternatively, an industrial or commercial firm may use energy primarily to obtain process steam, and in doing so it finds it can also produce electricity relatively inexpensively. As a result of jointly producing both types of energy (e.g., steam and electricity), total energy requirements may be reduced by as much as 30 percent.[1] Although there is potential for exploiting cogeneration from commercial and residential heating systems, it is believed that the bulk of the cogeneration will come from industrial applications.

It is widely believed that cogeneration, particularly coal-fired steam, is capable of producing relatively inexpensive energy.[2] The cost tends to be competitive with both the short-run marginal costs of existing electric systems and the long-run marginal (and average) cost of a new baseload coal facility. Unfortunately, the contribution of cogenerators to system reliability is an unsettled issue and clouds a complete evaluation. On the basis of favorable cogeneration economics and the rather large industrial demand for process steam in the service areas of Maryland utilities, an opportunity exists to increase sharply the amount of electricity produced by cogeneration.

Maryland utilities have had some limited experience with industrial cogeneration in their service areas. The Getty Oil Company operates a large cogeneration project with DP&L near Wilmington, Delaware. The Delaware City 1 and 2 units simultaneously produce process steam and electric power for the refinery. Any excess power is sold back to DP&L. The Celanese Corporation in

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[1] Energy in America's Future, Resources for the Future, p. 160. The RFF study reports four additional benefits: (1) capital savings in generation equipment; (2) transmission and distribution savings; (3) reduced cooling water requirements; and (4) reduced siting and licensing lead times.

[2] Argonne National Laboratory estimates that the average total cost of cogenerated power may be as low as 2.5¢/kWh (in 1980 dollars) assuming a relatively large, efficient cogeneration facility. This is well below both the long-run and short-run marginal costs of power on most utilities (17).

Cumberland, Maryland has in the past operated a 10 megawatt facility with Potomac Edison, but that unit has been retired since 1978. The Westvaco Corporation in Luke, Maryland currently operates a large facility and sells a small amount of power to Potomac Edison. On the basis of Company surveys, there appears to be a significant potential to expand cogeneration and small power production in the Allegheny Power System service area.

E. A List of Electric Utility Industry Definitions

The final section of this chapter provides definitions of some of the terms commonly used by electric utility generation planners. Most of these terms are used extensively throughout this Report, and particularly in Chapters I and II.

- Cycling Plants are units designed to operate at relatively high efficiency, but which can be adjusted to meet changing loads and can operate well under relatively frequent on-off cycles.

- Peaking Plants are units designed to operate only for short periods of peak demand, usually for only a brief part of the day during a few months of the year.

- Demand is the amount of electric power required by customers at any given instant in time, usually stated in megawatts (MW) or kilowatts (kW). One kW is the amount of power needed to light ten 100 watt light bulbs, and a megawatt is 1,000 kilowatts.

- Peak Demand is a maximum demand experienced during some time interval, such as a day or year. Peak demand in the tables in this chapter is the average power used over the 60 minute period of heaviest demand during a given year.

- Load Factor is the ratio of the average load (MW) to the peak load during the time period being measured. An annual system load factor, SLFa, is defined as:

$$SLFa = \frac{SEa}{SPLA \times 8760}$$

where: SLFa = annual system load factor
SEa = annual system energy output (MWh) (energy sales plus losses)
SPLa = annual system peak load (MW), and
8760 is the number of hours in a year (8784 in a leap year)

- Capacity Factor is the ratio of the average load (MW) on a plant or entire system to the capacity rating (maximum rated output, MW) of the plant or system for the time period being measured.

- Reserve Margin is the difference between system maximum capacity (MW) and system peak load, divided by the system peak load, for any given moment in time. The most commonly used reserve margin is defined at the time of the system peak demand:

$$RMp = \frac{SCp - SDp}{SDp}$$

where: RMp = system reserve margin
SCp = system maximum capacity at time of peak
SDp = system peak demand

- Base Load Plants are generating units designed to be run at high efficiency on a continuous basis over long periods of time.

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CHAPTER III

AIR IMPACT

The majority of gaseous airborne pollutants result from man-made combustion and abrasive processes, including commercial and residential heating, generation of electricity by fossil fuels, mobile sources (e.g., cars, boats, and other vehicles), various industrial processes, and refuse incineration. Industrial combustion processes are major sources of sulfur dioxide and nitrogen oxides. Automobile exhaust is rich in nitrogen oxides, hydrocarbons, and carbon monoxide.

Some particulates emissions are due to industrial processes. However, in many cases, the greatest mass of particulate emissions is due to blowing dust from activities such as handling of materials (e.g., coal and gravel), construction, and transportation (e.g., particulates dislodged along roadways by vehicles and emissions from uncovered trucks and rail cars). Erosion of exposed earth and sand by the wind is also a major source of blowing dust. In some cases, natural particulate emissions such as wind-blown dust and pollen can exceed man-made emissions by an order of magnitude (1).

A. Sources of Major Pollutants

Figures III-1 through III-5 present data on emissions of five major pollutants by source category for 1975 through 1978 in the State of Maryland. Table III-1 is the total statewide emissions inventory. During 1975 and 1976, Maryland power plants contributed 63 percent of the sulfur oxides, 30 percent of the particulates, and 28 percent of the nitrogen oxides (see Figure III-6 for plant locations). Since power plants use relatively efficient combustion processes, they contribute less than 1 percent of total hydrocarbon and carbon monoxide emissions.

Emissions from power plants vary depending on the composition of the fuel, operating conditions, and control equipment (precipitators and scrubbers). During combustion, sulfur in coal and oil is almost completely converted to SO_2 and emitted through the stack. The preponderance of NO_x emitted is due to reactions between O_2 and N_2 in the air at elevated temperatures. These NO_x emission rates are sensitive to fuel type, burner design, flame temperature, and the amount of excess air entering the furnace. Particulates emitted include noncombustible fuel residues (silicates, metal salts, sodium chloride) and incompletely burned organic materials. Coal combustion also releases large amounts of soil minerals embedded in the coal. Relatively small amounts of fluoride, mercury, beryllium, and various radioactive materials may also be released when coal is burned.

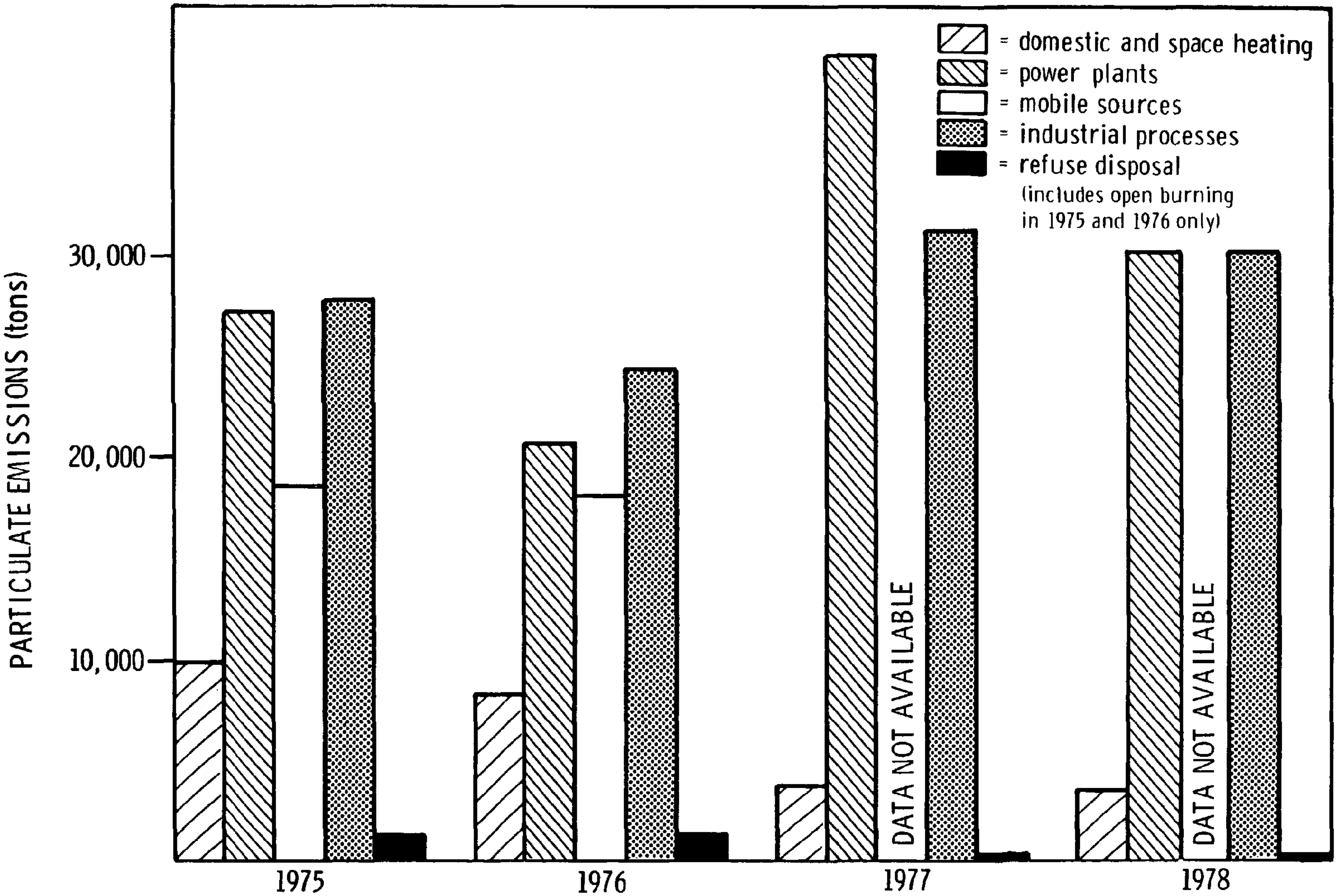


Figure III-1. Statewide particulate emissions, 1975-1978 (data from Ref. 2).

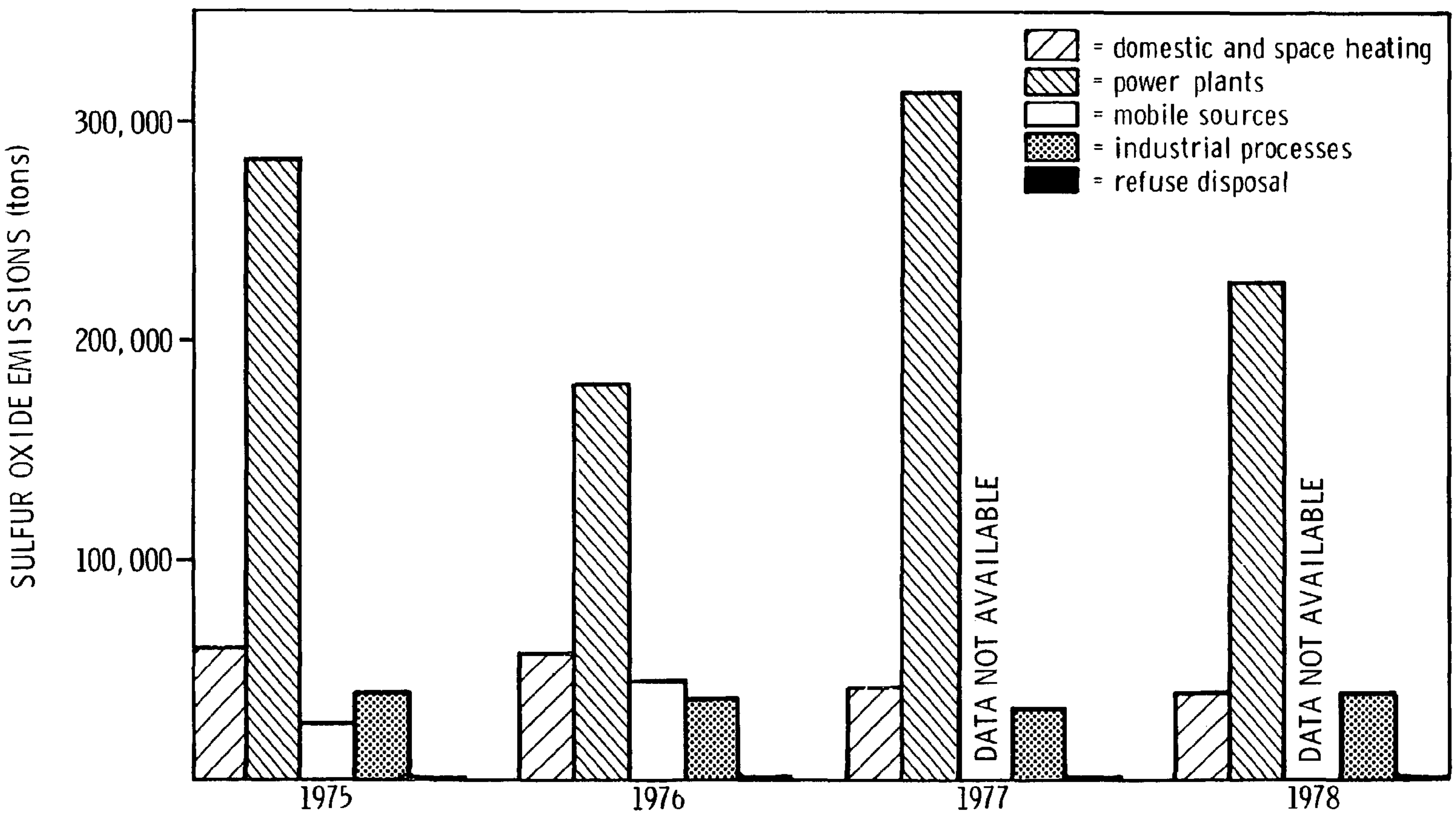


Figure III-2. Statewide sulfur oxide emissions, 1975-1978 (data from Ref. 2).

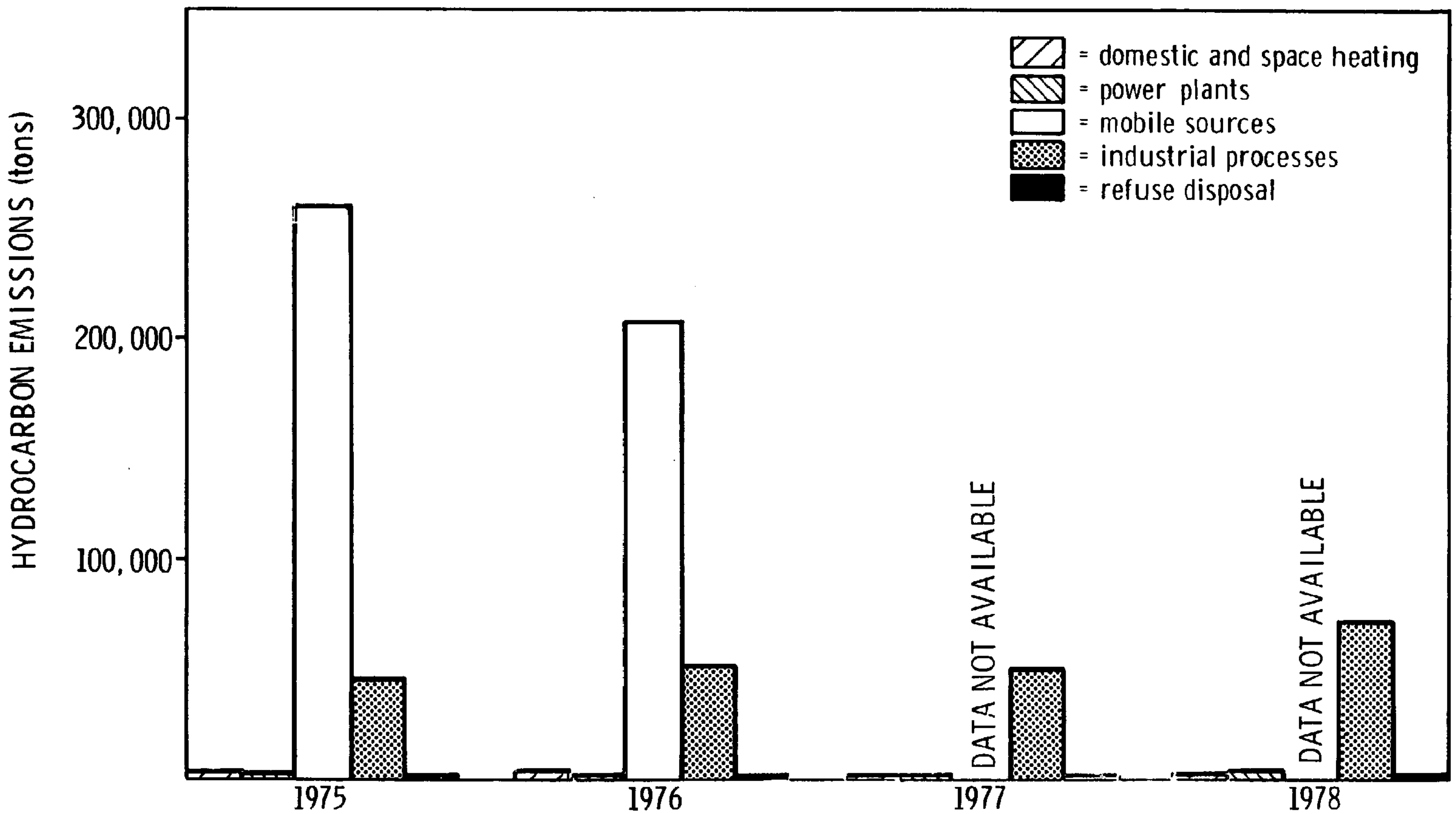


Figure III-3. Statewide hydrocarbon emissions, 1975-1978 (data from Ref. 2).

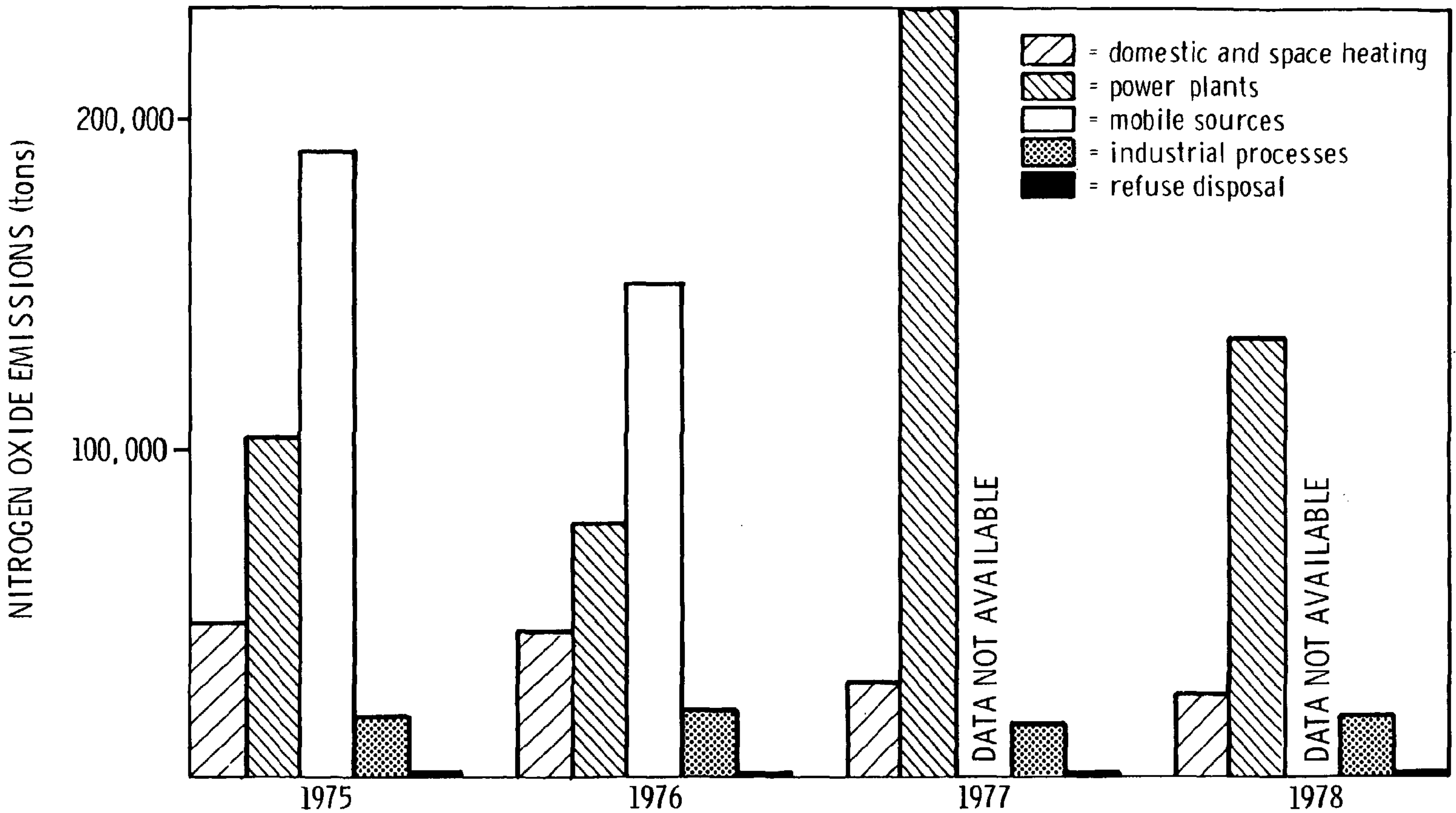


Figure III-4. Statewide nitrogen oxide emissions, 1975-1978 (data from Ref. 2).

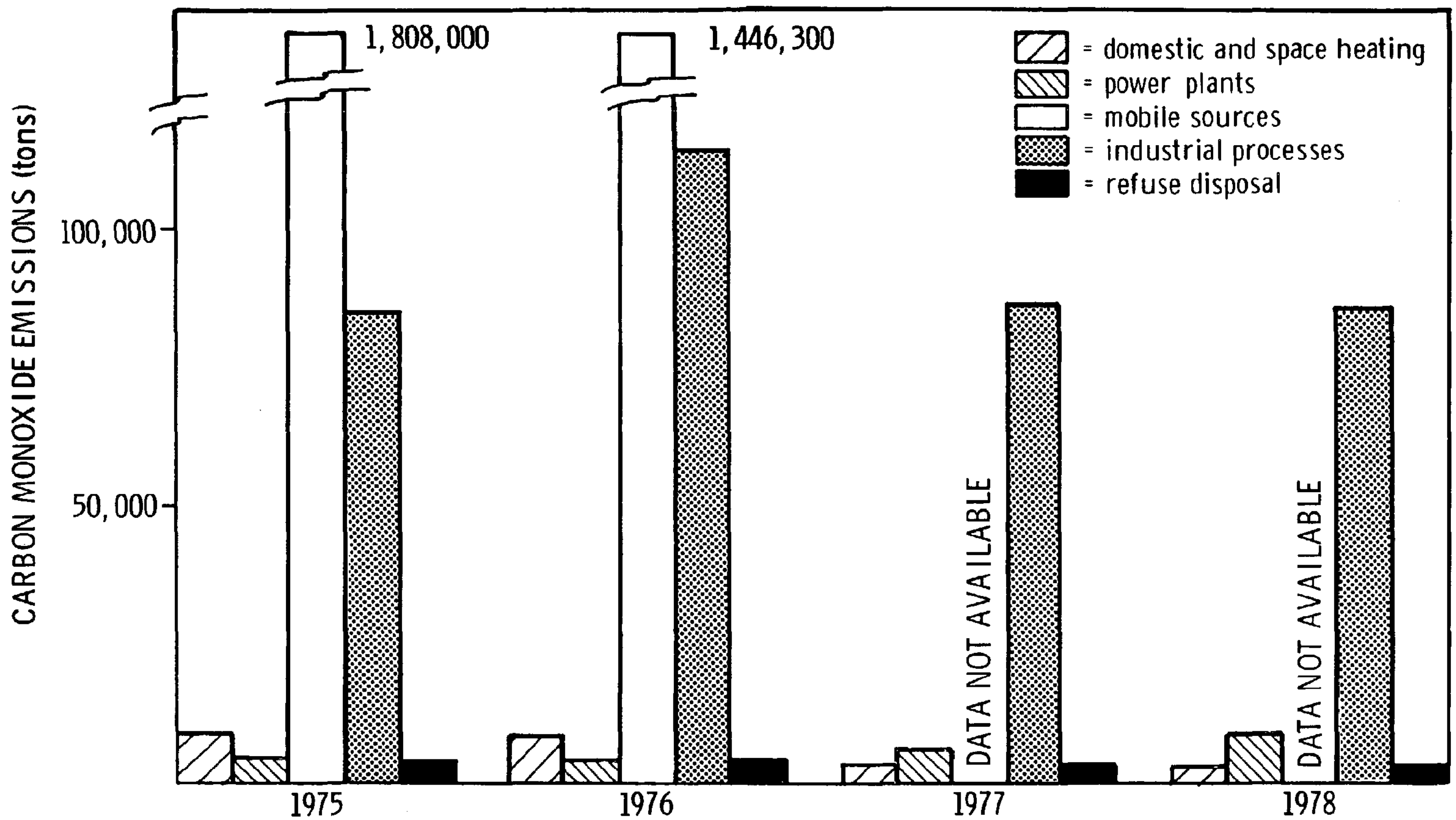


Figure III-5. Statewide carbon monoxide emissions, 1975-1978 (data from Ref. 2).

B. Emission Trends of Major Pollutants

Total Suspended Particulates (TSP)

National emissions of particulates showed considerable reduction from 1970 to 1978 (Fig. III-7). A continuation of this trend is predicted by a comprehensive simulation model developed by the U.S. Environmental Protection Agency (EPA) -- the Strategic Environmental Assessment System (SEAS) (4). This model incorporates recent modifications and data files developed by the Energy Research and Development Administration (ERDA), now a part of the Department of Energy. The model assumes the use of coal will approximately double by 1990. Figure III-8 shows the total predicted emissions of TSP for the U.S. in 1985 and 1990, relative to 1975 emissions. Estimates of total particulate emissions in Maryland (excluding mobile sources) for recent years fluctuate with time (see Table III-1) and show no clear trend.

Sulfur Dioxide (SO_2)

National emissions of SO_2 showed a general increase until 1970, but have decreased slightly since then. (see Fig. III-9). EPA projections made in 1978 predicted that increased use of coal would cause a reversal of this downward trend, with SO_2 emissions increasing about 10 percent over 1975 emissions by 1985 (see Fig. III-8).

Total sulfur oxide emissions in Maryland for 1975 - 1978 (Table III-1) (excluding mobile sources) have fluctuated with time, showing no clear trend.

Nitrogen Oxides (NO_2)

U.S. emissions of NO_x from power plants and motor vehicles have shown an increasing trend, but since 1976 the emissions from motor vehicles have stabilized because the increase in miles travelled has been offset by decreased emissions due to automotive pollution control techniques (5) and increased mileage per gallon.

Figure III-8 shows the total predicted emissions for nitrogen oxides for the U.S. for 1985 and 1990 to be about the 1975 level. In Maryland, NO_x emissions showed large variations from one year to the next due to changes in the emission inventories for power plants.

Hydrocarbons and Carbon Monoxide

Automobiles are the major sources of both hydrocarbons and carbon monoxide. Advanced automotive emission controls have significantly reduced emissions from new cars. As old cars are phased out, national HC and CO emissions will be reduced, as shown in Fig. III-8. Additional reductions may result if increased gasoline prices reduce a significant reduction in vehicle miles travelled. Emissions of hydrocarbons and carbon monoxide for Maryland in recent years are shown in Table III-1.

Power Plants (>90MW) Within or Adjacent to Maryland (●)

(Capacity in MW)

Plant Name	Utility	Steam	Gas Turbine	Fuel of Steam Unit
1. Benning Road[a]	PEPCO	597		Oil
2. Brandon Shores[b]	BG&E	1,250		Coal
3. Buzzard Point[c]	PEPCO	222	252	Oil
4. Calvert Cliffs	BG&E	1,620		Nuclear
5. Chalk Point[d]	PEPCO	1,105[e]	48	Coal/oil
6. C.P. Crane	BG&E	384	14	Oil[f]
7. Dickerson[g]	PEPCO	545	13	Coal
8. Gould Street	BG&E	103		Oil
9. Morgantown	PEPCO	1,163	248	Coal
10. Notch Cliff	BG&E		128	
11. Perryman	BG&E		204	
12. Potomac River[h]	PEPCO	480		Coal
13. Riverside	BG&E	321	172	Oil
14. R.P. Smith	Pot.Ed.	129		Coal
15. Vienna[i]	DELMARVA	241	17	Oil
16. Wagner	BG&E	988	14	Oil/coal
17. Westport[j]	BG&E	209	118	Oil

Plants Owned by Out-of-State Utilities (▲)

18. Conowingo (Philadelphia)
19. Mount Storm (VEPCO)
20. Possum Point (VEPCO)

Proposed Future Power Plant Sites (○)

21. Bainbridge[k]
22. Canal (Philadelphia)
23. Della Brooke Farm (So. Md. Elec. Coop.)
24. Douglas Point (PEPCO)
25. Elms[k]
26. Point of Rocks (Pot. Ed.)
27. Seneca Point (Philadelphia)
28. Summit (DELMARVA)

(a) Unit 13 (47 MW) is scheduled to be retired in 1982.
(b) Unit 1 is scheduled to begin operation in mid-1984, Unit 2 in early 1988.
(c) Units 1-6 (222 MW) are scheduled to be retired in 1982.
(d) Scheduled to add Unit 4 (600 MW, oil) in 1982.
(e) Capacity will increase to 1,335 MW at end of 1982 following the addition of more stringent emission controls.
(f) Commenced legal process for conversion to coal.
(g) Proposed addition of Unit 4 (300 MW, coal) in 1993.
(h) Units 1-2 (174 MW) are scheduled to be retired in 1984.
(i) Units 5-7 (74 MW) were scheduled to be retired in 1980; also scheduled is the addition of Unit 9 (500 MW, coal with DELMARVA retaining ownership of 325 MW) in 1987.
(j) Units 1, 13, 14 (19, 16, 16 MW) are scheduled to be retired in 1982; while Unit 3 (58 MW) is scheduled to be retired in 1987.
(k) Power Plant Siting Program required site.

Figure III-6. Power plants in the Maryland region.

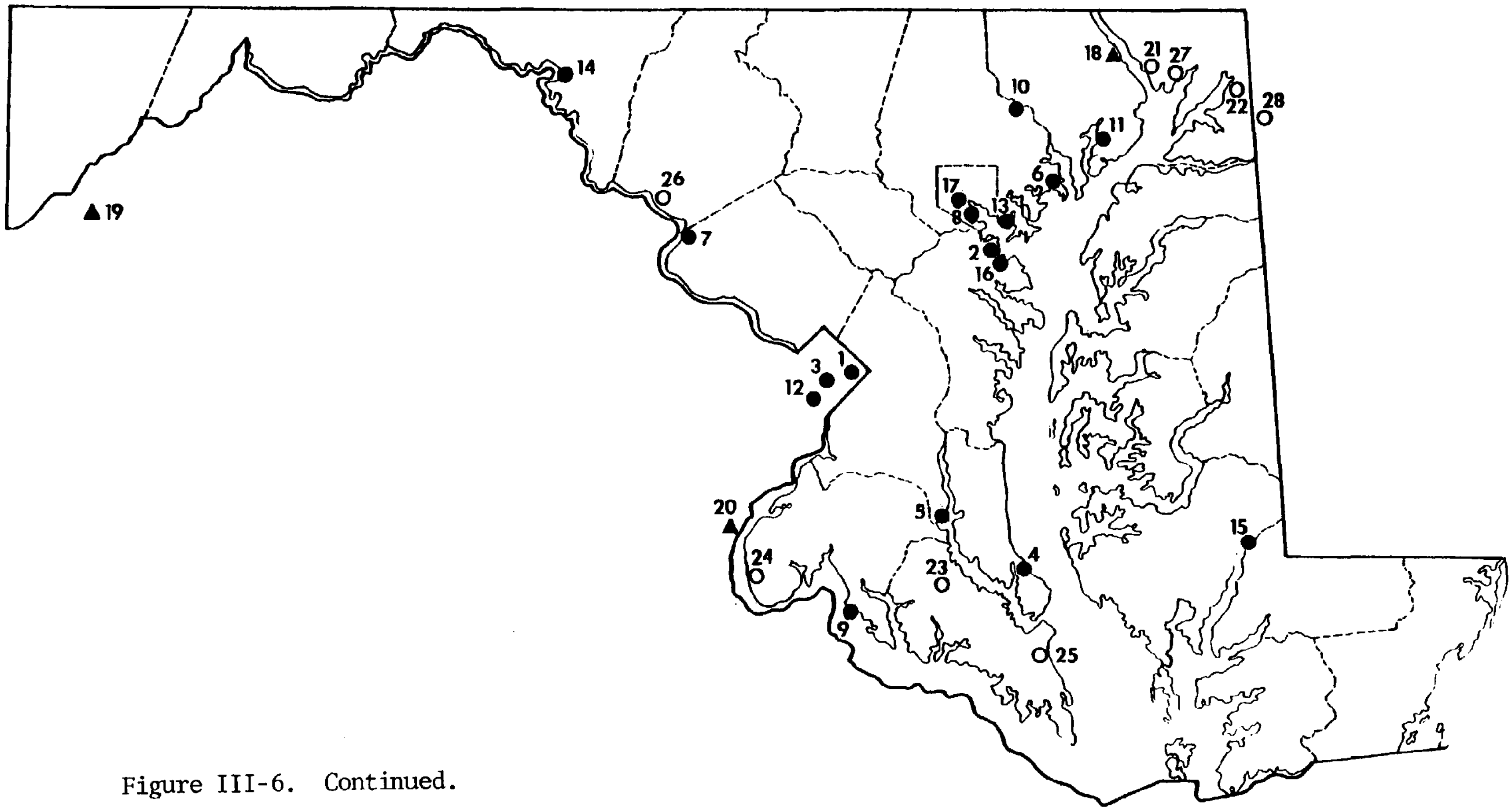


Figure III-6. Continued.

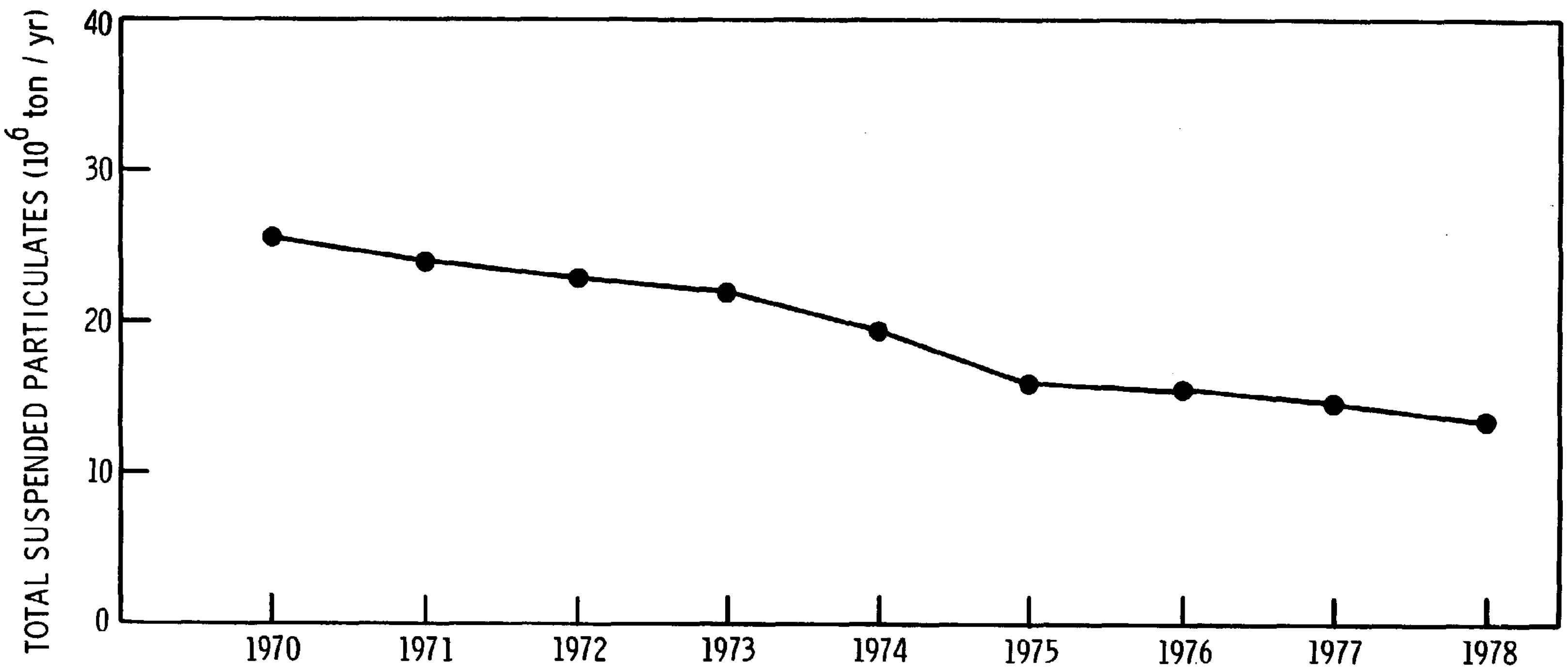


Figure III-7. Estimates of total suspended particulate emissions for the United States (data from Ref. 6).

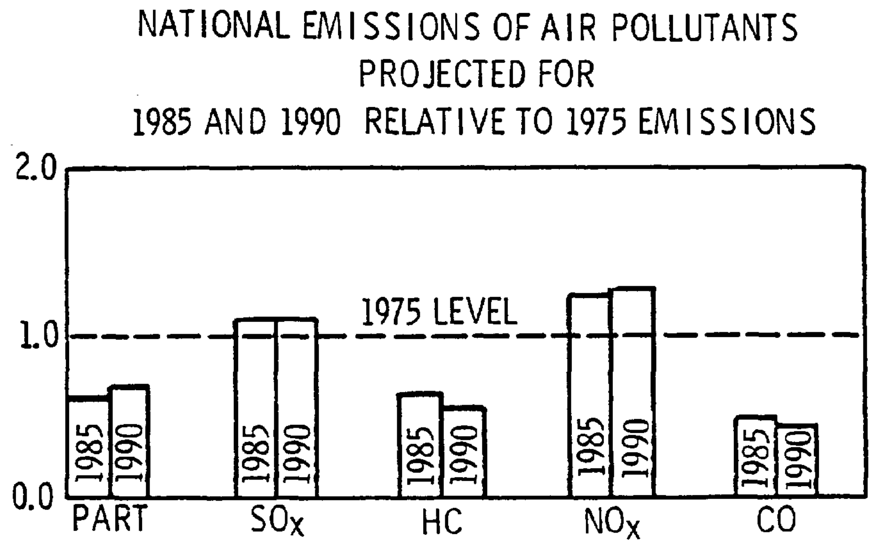


Figure III-8. National emissions of major air pollutants projected by EPA for 1985 and 1980 relative to 1975 emissions (data from Ref. 4).

Table III-1. Statewide Total Emissions Inventory for the Five Major Source Categories for 1975-1978[(a)]

	Total Emissions (tons/year)[(b)]			
	1975	1976	1977	1978
Particulates				
Including mobile sources	85,000[(c)]	73,500	--[(d)]	--
Excluding mobile sources	66,400	55,400	76,100	67,200
Sulfur Oxides				
Including mobile sources	409,800	318,700	--	--
Excluding mobile sources	383,300	274,100	390,200	308,300
Hydrocarbons				
Including mobile sources	311,600[(e)]	263,300	--	--
Excluding mobile sources	76,200	56,100	52,700	74,300
Nitrogen Oxides				
Including mobile sources	359,000	288,200	--	--
Excluding mobile sources	169,700	138,900	273,700	177,700
Carbon Monoxide				
Including mobile sources	1,910,200	1,577,000	--	--
Excluding mobile sources	107,400	130,700	99,300	100,400

(a) Data from Ref. 2. Emission data are obtained from estimates of indicators such as fuel consumption, production rates, control efficiencies, and vehicle miles traveled. Average emission factors, which relate these indicators to emission rates for specific source categories, are used to derive total emissions (3).

(b) Does not include miscellaneous source categories.

(c) These are "man-made" particulate emissions. Particulate "emissions" due to natural causes (e.g., wind-blown dust and pollen) vary widely with place and time and can exceed man-made emissions by an order of magnitude.

(d) Data for mobile sources not available.

(e) In addition, about 150,000 tons per year is released from asphalt roads in the State. This quantity can be reduced to 20,000 to 25,000 tons per year by current use of a different type of road tar. Emission from an asphalt-surfaced road decreases significantly over a period of 1 to 2 years.

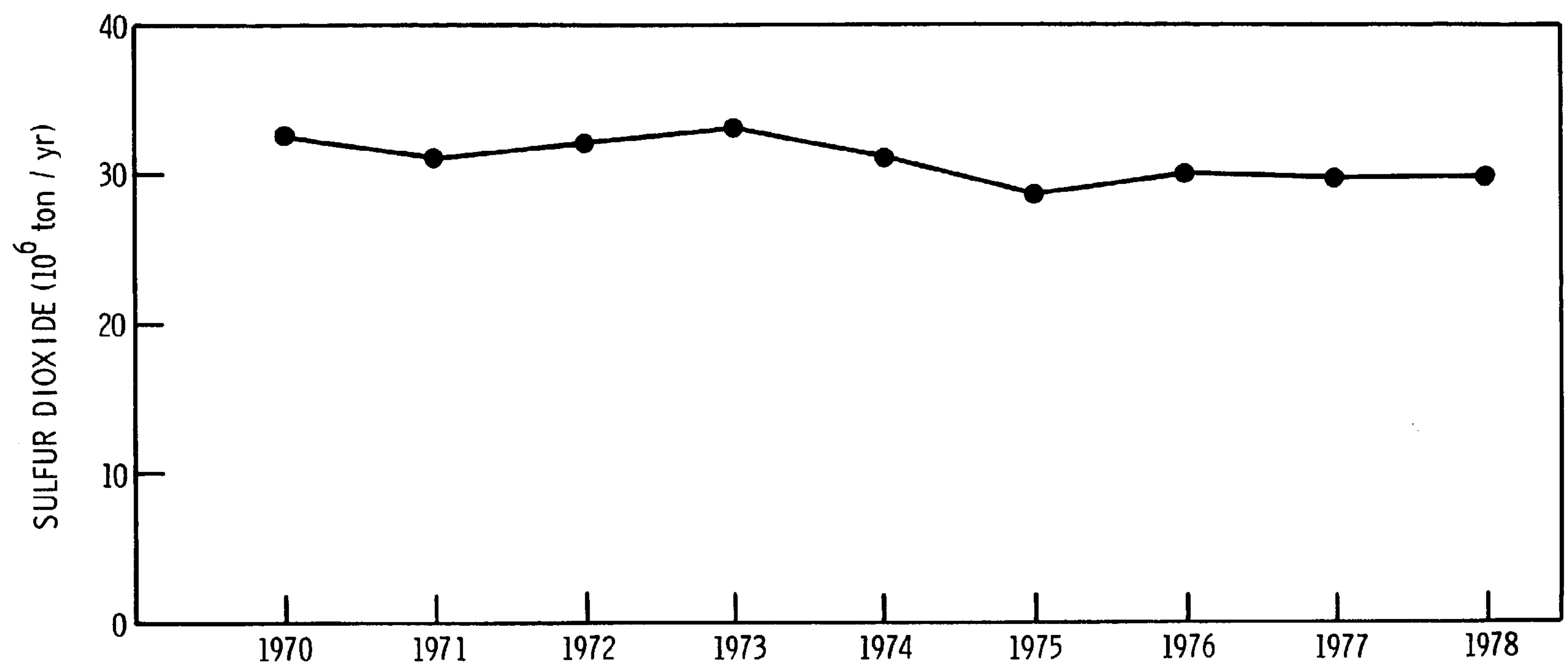


Figure III-9. Estimates of sulfur oxide emissions for the United States (data from Ref. 6).

C. Standards

Ambient air quality is measured and defined as ground-level concentrations of pollutants. Federal and State agencies are attempting to attain and maintain good air quality by: 1) regulating pollutant groundlevel concentrations through ambient air quality standards, 2) controlling emissions from new and existing sources through source-emission standards, and 3) restricting sulfur content of fuels. Emissions from new sources are controlled through an extensive new source review process.

Ambient Air Quality Standards

Ambient air quality standards have been established by the EPA for ground-level concentrations of certain pollutants and have been adopted by State of Maryland. The National Ambient Air Quality Standards (NAAQS) are listed in Table III-2. The national primary standards are designed to protect human health, whereas the secondary standards are concerned with the protection of human welfare (i.e., the material and aesthetic effects of pollution).

Emission Limitations for Existing Fuel-Burning Installations

Sulfur content of fossil fuels is controlled to reduce the ground-level concentration (GLC) of SO_2. Limitations are less strict in Maryland rural air quality areas (Areas I, II, V, and VI -- see Fig. III-10) than in urban areas (III and IV). Nitrogen oxide emissions are limited for all installations in areas III and IV and for installations that commenced operations after 12 May 1972, in other areas of the State. Visible emissions other than steam are restricted throughout Maryland. The total mass of particulate emissions is also regulated. Dust collectors are required for installations burning residual oil in areas III and IV. (See Table III-3).

New Source Review

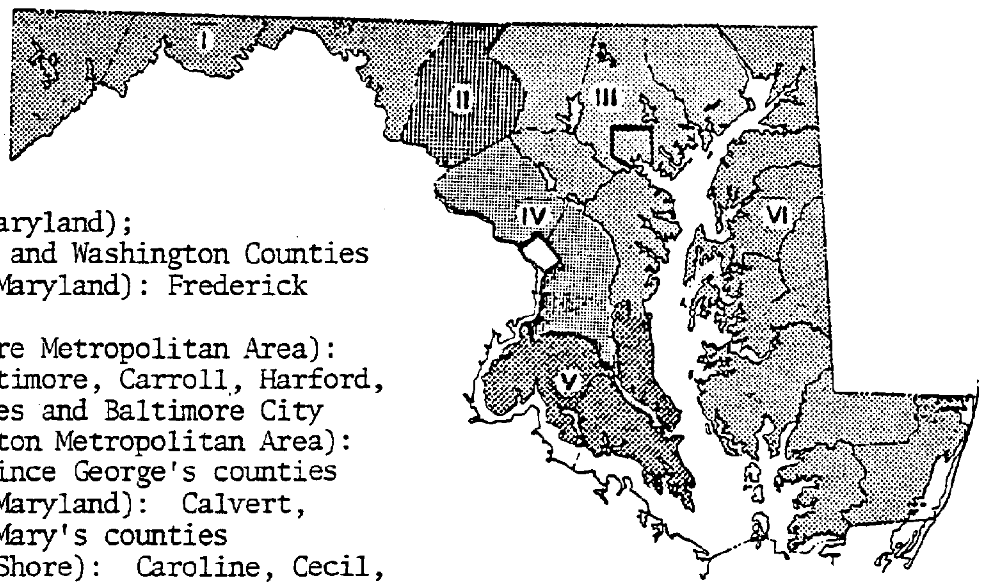
New proposed utility steam-generating units with a heat input greater than 250 x 10^6 Btu/hr, or major modifications at installations of this size that increase controlled emissions of any pollutant by more than 100 tons per year, are subject to New Source Review. This review must demonstrate that all source emissions from these installations meet applicable New Source Performance Standards (NSPS). These standards were originally established by EPA in December 1971 under authority of the Clean Air Act of 1970 for certain new sources beginning operation after 17 August 1971 (7, 8). To satisfy the requirements of the Clean Air Act Amendments of 1977, EPA has adopted revised standards of performance for electric utility steam generating units for which construction commenced after 18 September 1978 (9). Table III-4 gives the two sets of NSPS for utility boilers.

In addition, the operator must demonstrate that the new unit it will not produce or exacerbate any violations of NAAQS, and that the increased emissions of SO_2 and TSP due to the unit will not produce increased ground-level concentrations in excess of allowable Prevention of Significant Deterioration

Table III-2. National Ambient Air Quality Standards and Prevention of Significant Deterioration Increments[(a)]

Pollutant	National				PSD increments ($\mu g/m^3$) by class		
	Primary		Secondary				
	$\mu g/m^3$	ppm	$\mu g/m^3$	ppm	I	II	III
Sulfur oxides							
Annual arithmetic	80	0.03			2	20	40
24-hr maximum[(b)]	365	0.14			5	91	182
3-hr maximum[(b)]			1,300	0.5	25	512	700
1-hr maximum[(c)]							
Suspended particulate matter							
Annual geometic mean	75		60[(d)]		5	19	37
24-hr maximum[(b)]	260		150		10	37	75
Carbon monoxide							
8-hr maximum[(b)], mg/m^3	10	9	10	9			
1-hr maximum[(b)], mg/m^3	40	35[(e)]	40	35			
Hydrocarbons (nonmethane)							
3-hr (6-9AM) maximum[(b)]	160	0.24	160	0.24			
Nitrogen dioxide							
Annual arithmetic mean[(f)]	100	0.05	100	0.05			
Ozone							
1-hr maximum[(g)]	235	0.12	235	0.12			
Lead							
Quarterly average	1.5						

(a) NAAQS figures from Ref. 10 and 11, PSD increments from Ref. 12.
(b) Not to be exceeded more than once per year.
(c) Not to be exceeded more than once per month.
(d) A guide to be used in assessing implementation plans to achieve the 24-hour standard.
(e) The EPA is proposing to lower the primary 1-hour standard to 25 ppm.
(f) A short-term (e.g., 1-hour average) standard for NO_2 is under consideration by the EPA.
(g) The ozone standard was changed from 160 $\mu g/m^3$ and 0.08 ppm in January 1979.



AREA I (Western Maryland);
Allegany, Garrett and Washington Counties
AREA II (Central Maryland): Frederick County
AREA III (Baltimore Metropolitan Area):
Anne Arundel, Baltimore, Carroll, Harford, and Howard counties and Baltimore City
AREA IV: (Washington Metropolitan Area):
Montgomery and Prince George's counties
AREA V (Southern Maryland): Calvert, Charles, and St. Mary's counties
AREA VI (Eastern Shore): Caroline, Cecil, Dorchester, Kent, Queen Anne's, Somerset, Talbot, Wicomico, and Worchester counties.

Figure III-10. The six air quality control areas in Maryland. From Ref. 13.

Table III-3. Restrictions in Fuel Sulfur Content and Emissions of Criteria Pollutants from Fuel Burning Equipment for Rural and Urban Areas of Maryland.

Parameter	Rural Limitation (Regions I, II, V, VI)	Urban Limitation (Regions III, IV)
Visible emissions other than water	20% opacity except 40% opacity not more than 6 min/hour during startup and soot blowing	None allowed except 40% opacity not more than 6 min/hour during startup and soot blowing
TSP emissions:		
Residual oil	0.1 lb/10^6 Btu[(a)]	0.01 gr/dscf,[(b)] dust collectors required
Solid fuel	Same as oil	0.03 gr/scfd,[(c)] dust collectors required
Sulfur limitation:[(d)]		
Solid fuel	3.5 lb/10^6 Btu[(e)]	1.0% (1.7 lb/10^6 Btu[(e)])
Residual fuel oil	2.0%	1.0%
Distillate fuel oil	0.3%	0.3%

(a) For new installations with more than 250 x 10^6 Btu/hour heat input. Higher emissions are allowed for installations existing before 17 Jan 1972 and for smaller installations (up to 0.6 lb/10^6 Btu).

(b) 0.02 gr/dscf for equipment constructed prior to 1 July 1975; 0.03 gr/ascf for equipment with a heat input less than 50 x 10^6 Btu/hour.

(c) 0.05 gr/dscf for installaions with a heat input less than 250 x 10^6 Btu/hour.

(d) Or equivalent if flue gas desulfurization is used.

(e) Not regulated if total fuel-burning equipment on premises has a heat input less than 100 x 10^6 Btu/hour.

Table III-4. Original (1971) and Revised (1978) New Source Standards of Performance for Steam Generators Fired by Fossil Fuels

Pollutant	Original Standard Applicable to boilers constructed 17 Aug 1971 to 18 Sept 1978	Revised Standard Applicable to boilers constructed after 18 Sept 1978
Particulate matter	0.10 lb per million Btu heat input, maximum 2-hr average	0.030 lb per million Btu heat input, maximum 2-hr average
	20 percent opacity; except that 27 percent opacity is permissible for not more than 6 min in any hour	Same
		99% of uncontrolled emissions when solid fuel is combusted or 70% when combusting liquid fuel
Sulfur dioxide	0.80 lb per million Btu heat input, maximum 2-hr average when liquid fossil fuel is burned	Same[b]
	1.2 lb per million Btu heat input, maximum 2-hr average when solid fuel is burned	Same[b]
		90 percent reduction of uncontrolled emission[c]
Nitrogen oxides	0.2 lb per million Btu heat input, maximum 2-hr average, expressed as NO_2, when gaseous fossil fuel is burned	Same[b]
	0.30 lb per million Btu heat input, maximum 2-hr average, expressed as NO_2, when liquid fossil fuel is burned	Same[b]
	0.70 lb per million Btu heat input, maximum 2-hr average, expressed as NO_2, when solid fossil fuel (except lignite) is burned	0.60 lb per million Btu heat input, maximum 2-hr average, expressed as NO_2, from combustion of bituminous coal.
		0.50 lb per million Btu heat input, maximum 2-hr average, expressed as NO_2, from combustion of subbituminous coal, shale oil, or any solid liquid or gaseous fuel derived from coal.

(a) Revised from 1978 CEIR (14)

(b) 30-day rolling average.

(c) 30-day rolling average. For sources emitting less than 0.60 lb per million Btu, the percent reduction required is 70%. No reduction is required when the facility uses liquid or gaseous fuel and emits less than 0.2 lb per million Btu.

Table III-5. Emissions of TSP and Trace Contaminants Subject to PSD Analysis for a Hypothetical Coal-Fired Power Plant Consuming 100 ton/hr of Coal

	Uncontrolled Emissions		Controlled Emissions			
	Content in Coal[a] (ppm)	Uncontrolled Emission Rate (lb/hr)	Assumed Control Efficiency (%)	(g/s)	(ton/yr)	PSD[b] *de minimus* (ton/yr)
TSP	224 lb/ton[c]	22,400	99.7	8.0	350	10
Pb	35 ± 44	7.0	99.0	0.0085	0.3	0.6
Hg	0.20 ± 0.20	0.04	5.0	0.0050	0.17	0.10
Be	1.6 ± 0.8	0.31	90.0	0.004	0.13	0.004
F	61 ± 21	12.0	90.0	0.15	5.4	3.0
As	14 ± 18	2.8	90.0	0.035	1.3	N/A[d]

[a] Measured standard deviations for 101 coals. Data from Ref. 15.

[b] New sources and modifications which are "major" under the PSD and non-attainment regulations of 8 August 1980 require an air quality analysis for all pollutants emitted in amounts greater than PSD *de minimus* values.

[c] Flyash production; assumes 14% ash content.

[d] Not established.

(PSD) increments (see Table III-2). An ambient air quality analysis must be carried out for all other pollutants emitted at rates greater than specified de minumus values. Several of these will be relevant for coal-fired power plants (see Table III-5). Utilities desiring to build plants in or near nonattainment areas must also demonstrate that their emission control equipment meets Lowest Achievable Emission Rate (LAER) requirements. If units are added in or near areas where ambient air quality standards are violated, other sources in the area must, in most cases, make offsetting emission reductions.

D. Health and Welfare Effects of Pollutants

The Clean Air Act of 1970 directs the Administrator of the EPA to compile a list of hazardous air pollutants and issue criteria documents describing the environmental effects of each. Ambient air quality standards are to be set for these material, using the best scientific evidence cited in the criteria documents. A safety factor is to be incorporated to protect the most sensitive elements of the population and to account for uncertainties in the data. The criteria documents and the resulting standards are to be reviewed and revised every 5 years.

To date, criteria documents have been issued and ambient air quality standards established for six pollutants: sulfur oxides, nitrogen oxides, total suspended particulates, photochemical oxidants (ozone), carbon monoxide, and lead. A hydrocarbon standard was issued as a guide for attaining ozone standards. The health effects on which the primary standards are based, and some of the welfare effects, are summarized below.

Total Suspended Particulates and Lead

Total suspended particulate material has been associated with a variety of adverse health effects in humans. These include decreased respiratory function, asthma, silicosis, asbestosis, and perhaps lung cancer. They are due both to the particulate nature of the suspended material and to its chemical composition. In addition, suspended particulate material impairs visibility and causes soiling.

The TSP ambient air quality standards established by the EPA in 1971 placed limits on the total mass of suspended material in the environment. However, more recent information suggests that the health effects are caused primarily by the smaller particles in the aerosol (16). The TSP standard is thus currently being revised to limit the mass of particles in the smaller size fractions as well as the total mass.

Emissions of specific components such as mercury, beryllium, and asbestos are regulated under national emission standards for hazardous pollutants. An ambient air quality standard for lead was promulgated in 1978 and standards may be forthcoming for other components of TSP as well.

Fluoride

Significant ambient concentrations of fluoride can alter bone metabolism in humans and animals. Exposures to moderate concentrations may cause bone deformation and kidney damage in humans. Prolonged exposure to low levels caused mottling of tooth enamel. Dairy cows are especially sensitive to the effects of fluoride because of their rapid rate of calcium metabolism. Even trace amounts in forage caused disabling bone and hoof disorders in dairy herds (17). Certain plants, including fruit trees and ornamentals, are injured by exposure to levels of atmospheric fluoride which are readily tolerated by animals.

The State of Maryland (18) has established ambient air quality standards for fluoride that limit the concentration in the ambient air to that which results in fluoride concentrations of 20 ppm in unwashed vegetable crops, 35 ppm in field crops, and 50 ppm in fruit tree leaves. (For applicable concentrations in other crops see COMAR, 1978, 10.18.04-01). In areas where vegetative sampling is not feasible, ambient air sampling may be required. The applicable standard is then 1.2 $\mu g/m^3$ of Fluor (as gaseous fluoride) (24-hour average) and 0.4 $\mu g/m^3$ of Fluor (72-hour average). If lime papers are used to monitor fluoride, the allowable catch is 2 μg Fluor per 100 cm^2 of paper.

Carbon Monoxide

Carbon monoxide interfers with the transport of oxygen from the lungs to body tissues. Symptons of carbon monoxide poisoning include headaches, impaired vision, and loss of coordination. These effects are accentuated at high altitudes (5,000 ft). Persons having heart or respiratory diseases are at increased risk. The severity of symptoms is related to both the concentration of carbon monoxide in the ambient air and the duration of the exposure.

In a healthy person engaged in normal activities, exposures to 20 $\mu g/m^3$ of carbon monoxide (twice the primary standard) for 8 hours produce no adverse effects. Eight-hour exposures to levels between 34 and 40 $\mu g/m^3$ (or 3.4 to 4 times the primary standard) may result in headaches, while levels between 40 and 100 $\mu g/m^3$ (or 4 to 10 times the primary standard) may impair visual perception, manual dexterity, or coordination (19). During strenuous activity, carbon monoxide is taken up more rapidly. The EPA recently (18 August 1980) proposed revising the 1-hour standard downward (to 25 ppm) to more adequately protect persons engaged in strenuous activity (51).

Sulfur Dioxide

Sulfur dioxide is a mild respiratory irritant which may produce bronchial asthma in susceptible persons (20). Continued and repeated exposure has been linked to the development of emphysema, bronchitis, and other chronic lung problems. However, some of the respiratory effects previously thought to result from SO_2 exposure appear to be due, instead, to sulfuric acid mist (see below). There is also some evidence of synergism between the effects of SO_2 and TSP, but this mechanism is not yet understood. High levels of sulfur dioxide produce leaf damage in susceptible plants; destruction of vegetative cover has occurred near some major SO_2 sources.

Mandated review of the SO_2 ambient standards is in progress. A draft criteria document has been circulated summarizing the results of recent studies on SO_2 toxicity. New ambient standards have not yet been proposed, however.

Under conditions of high humidity, or in the presence of ozone or suspended particulate material containing vanadium or other transition metals, sulfur dioxide is rapidly oxidized to form sulfuric acid mists and sulfate aerosols (see below). These are strong respiratory irritants. Monkeys exposed to moderate concentrations develop distinctive changes in lung tissue similar to those seen in obstructive lung diseases in humans (21). Sulfuric acid mists also cause damage to limestone and plants.

Sulfates

Sulfates are formed from sulfur oxides and sulfuric acid mist in the presence of other reactants such as fine particulates, nitrogen dioxide, hydrocarbons, ammonia, catalytic metals, and photochemical reaction products. Sulfate aerosols are transported long distances and may produce significant deteroration of visibility in rural areas. The presence of sulfuric acid and sulfates in the atmosphere is one major cause of the increased acidity of rain and snow found particularly in the northeastern part of the United States. Sulfates account for about 60 percent of the total non-carbonate acidity in precipitation while nitrates account for about 30 percent; the remaining 10 percent is caused by chlorides, ammonia, and other acids (22).

The use of tall stacks decreases local SO_2-sulfate pollution levels because of dispersion, but the pollutants will be carried far from their sources. This long-range transport, along with the complex precursor relationships between sulfur dioxide and sulfates, explains why a general decrease in SO_2 levels is not necessarily reflected in a similar trend for sulfates, as illustrated in Fig. III-11.

Although there is mounting evidence of health hazards associated with inhalation of sulfates, no standards for ground-level concentrations have been established. Regulation of atmospheric sulfates has been under consideration by EPA, but advances in monitoring and analytical techniques, as well as improved assessment of health hazards, are required before standards can be set (23).

Photochemical Air Pollution: Hydrocarbons, Ozone, Nitrogen Oxides, PAN

Nitrogen oxides and hydrocarbons react in sunlight to form a variety of oxidation products including ozone, peroxyacetyl nitrate (PAN), aldehydes, and particulate material (haze). The resulting mixture causes eye and lung irritation and increased susceptibility to infections. Exposures to oxidant levels commonly found in urban areas during stagnation conditions may lead to decreased lung function and asthematic attacks in susceptible individuals.

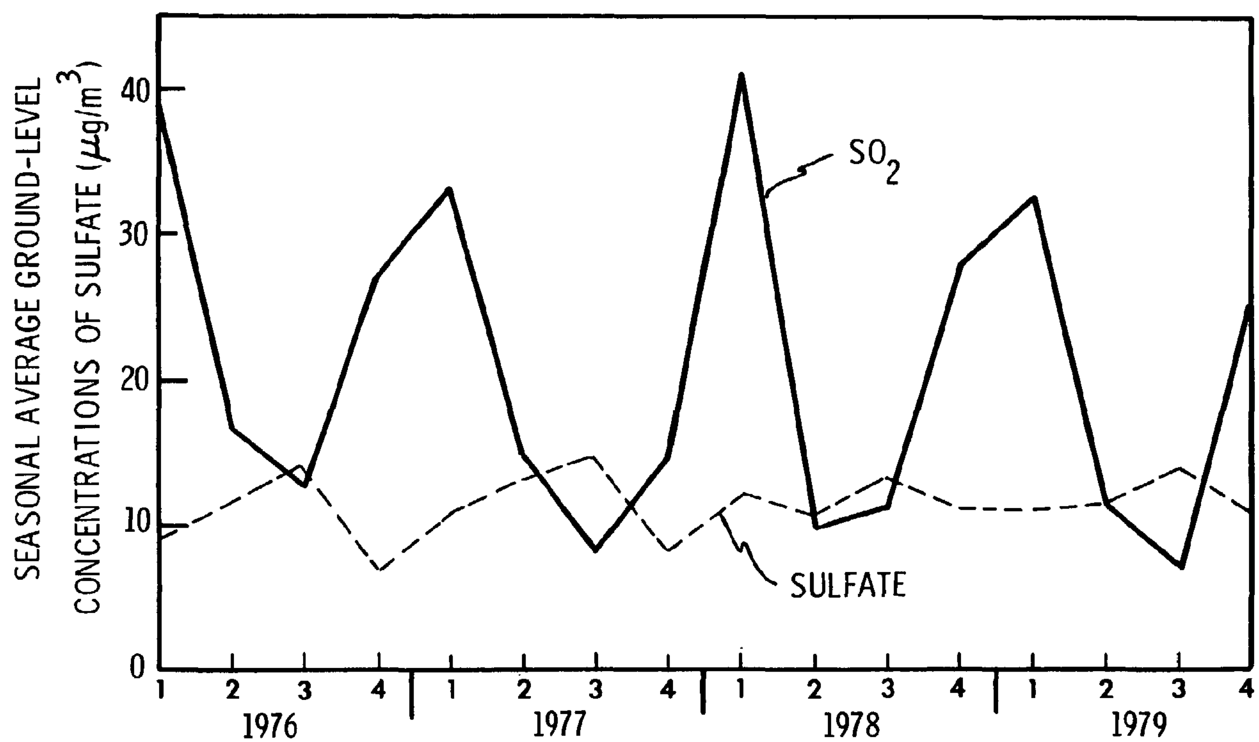


Figure III-11. Composite quarterly means of sulfate and SO_2 ground-level concentrations for all stations using the flame photometric method. Graph is for readers' information only -- many stations have less than 75% of the prescribed number of readings. (Graph based on data from Ref. 2).

The ozone component of smog produces rapid degradation of rubber and nylon and increases the rate of SO_2 oxidation in power plant plumes to form sulfuric acid mist. Both PAN and ozone damage commercial crops at concentrations below the current ambient air standard.

Many, if not most, areas of the eastern United States have ozone (oxidant) concentrations greater than the original standard of 80 ppb (oxidant). The sources of these exceedances have not been determined, but are believed to be natural or regional in many cases. The standard has recently been revised to allow 1-hour average concentrations up to 120 ppb (ozone). This change has greatly reduced the number and extent of rural nonattainment areas.

The ususal concentrations of hydrocarbons in ambient air have no adverse effects on health. However, prolonged exposure to levels of nitrogen oxides somewhat above the existing standard may lead to chronic obstructive lung disease.

Other Pollutants

A number of other compounds found in trace amounts in ambient air are known to have various adverse health effects. Emissions of some of these (e.g., beryllium, mercury, and asbestos) have been limited under the National Emissions Standards for Hazardous Pollutants (24). However, until more is known about the complex precursor relationship between emitted pollutants and the pollutants which ultimately cause health hazards, the EPA feels a sound and meaningful general strategy is to control ground-level concentrations only for the six major "criteria" pollutants: particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, hydrocarbons, and lead.

E. Status and Trends of Maryland Air Quality

All areas of Maryland are currently in compliance with the National Ambient Air Quality Standards, with the folowing exceptions: the Baltimore Metropolitan area is nonattainment for total suspended particulates, as shown in Fig. III-12. A previous TSP nonattainment area, Election District 8 in Luke, Maryland, is now unclassified. Portions of the cities of Hagerstown, Cumberland, and Baltimore and areas of high traffic density near Washington, D.C., are designated nonattainment for carbon monoxide. A proposal to change these CO areas to unclassifiable is presently under consideration. The Baltimore Metropolitan area (Air Quality Control Region III), shown in Fig. III-10, is nonattainment for ozone, as is Washington County and the Maryland portion of the metropolitan Washington, D.C., area. Previous ozone nonattainment areas in Garrett and Alleghany counties are now unclassified or have ambient levels below national standard (25, 26).

Trends in ambient air quality can be determined from analyses of ground-level concentrations measured at air quality monitoring stations. The national air quality trends are based on data from EPA's National Aerometric Data Bank (NADB). These data are gathered primarily through the monitoring activities of state and local air pollution control agencies (27).

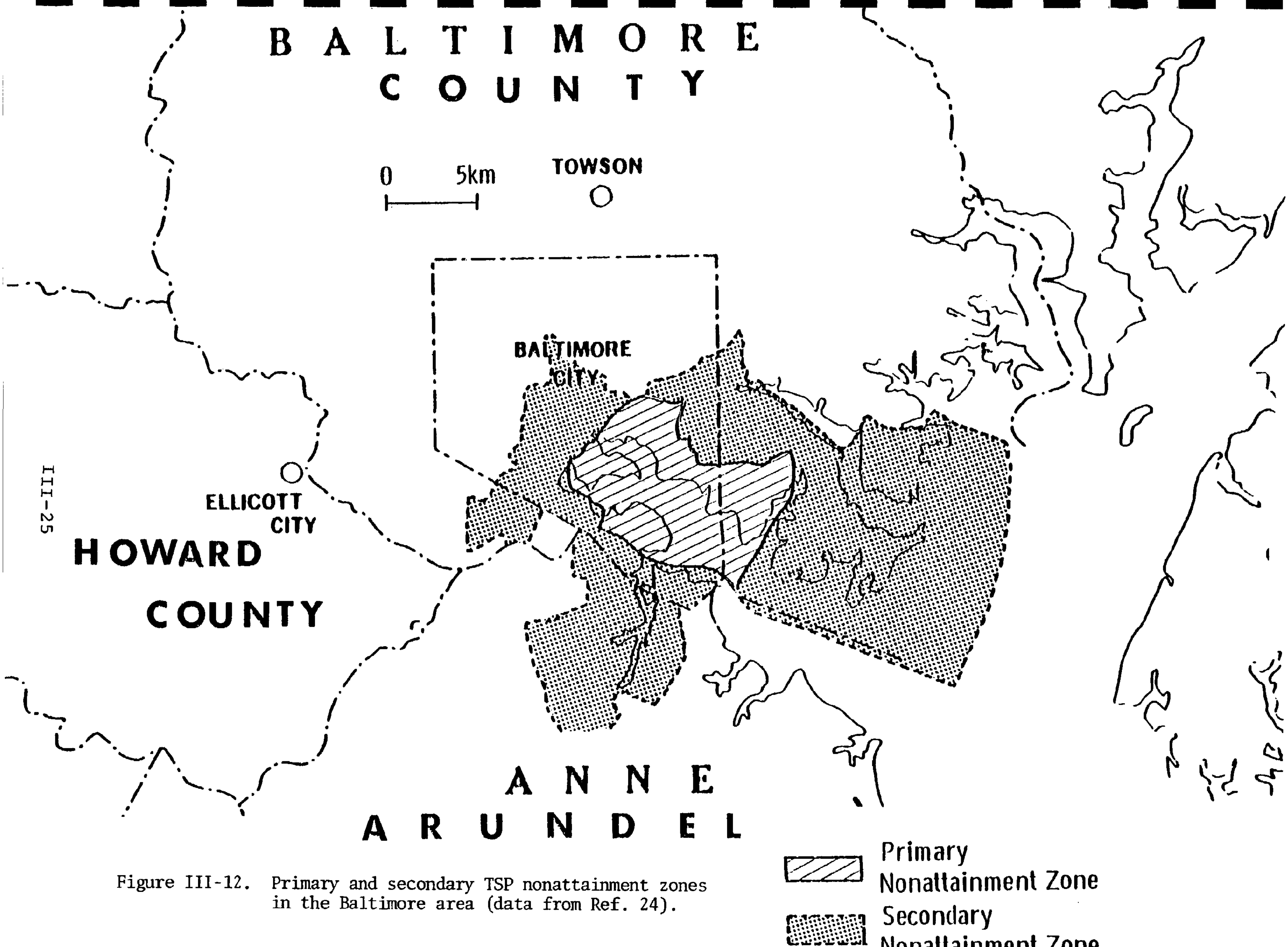


Figure III-12. Primary and secondary TSP nonattainment zones in the Baltimore area (data from Ref. 24).

Maryland data are reported by the Air Quality Program of the Department of Health and Mental Hygiene, which has stations throughout the State, mainly in the urban areas (2). Because stations are not distributed uniformly, the ground-level concentrations reported may not be representative of the overall status of air quality; but the trends, or changes, at these stations do indicate the statewide trends. Also, since many stations have been moved and the measurement methods have changed over the years, it is sometimes difficult to select stations with sufficient continuous data records to establish long-term trends. Therefore, in some cases, annual data may not be directly comparable.

Total Suspended Particulates

There has been a downward trend in TSP ground-level concentrations in Maryland over the past 10 years. Among 21 stations from which data were continuously available for the period, the number of sites showing a violation of the primary annual standard (75 $\mu g/m^3$) decreased from 9 in 1971 to 1 in 1979. The composite average for these stations was 78 $\mu g/m^3$ in 1971 and 49 $\mu g/m^3$ in 1979 (see Fig. III-13). The mean annual average value for all stations in Maryland decreased from 75 $\mu g/m^3$ in 1971 to 50 $\mu g/m^3$ in 1979 (see Fig. III-14).

A State Implementation Plan (SIP) has been prepared to bring the Baltimore Metropolitan nonattainment region into attainment with the primary NAAQS during 1982 and with the secondary standard by 1986. The SIP addresses the major causes of high values, which seem to be fugitive emissions from roads and industrial installations. The impact of the existing oil-fired power plants in this region appears minimal.

However, there are several power plants in attainment areas that are not in compliance with emission limitations. For example, Chalk Point Units 1 and 2 will be subject to a delayed compliance order (under a recently submitted SIP revision) calling for final compliance by January 1, 1983 (28).[1] Recent testimony indicates that the fugitive emission inventories used in preparing the SIP may have been greatly underestimated. SIP revisions are in preparation calling for additional emission reductions based on a corrected inventory. The need for stricter emission controls and a longer compliance period than originally proposed has become an issue in the pending coal conversions at Crane and Brandon Shores (29, 30).

Sulfur Dioxide (SO_2)

The entire State of Maryland is in compliance with the NAAQS for sulfur dioxide (25). Measurements of ambient sulfur dioxide levels made by the Maryland Department of Health and Mental Hygiene show a consistent downward trend in average SO_2 ground-level concentrations since 1974 (see Fig. III-15).

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[1]Wagner Unit 3 also was not in compliance as of January 1, 1982, but management has been granted 90 days to achieve compliance (28). Note that, Wagner and Chalk Point do not produce ambient TSP concentrations in excess of NAAQS at nearby air quality monitors.

Figure III-16 shows the seasonal trend in SO_2 ground-level concentration (measured by the flame photometric method). Higher levels in the heating months (first and fourth quarters) indicate that much of the SO_2 comes from local sources, primarily space heating using sulfur-containing fossil fuel. The SO_2 emissions from power plants may be expected to run counter to this seasonal variation since electrical demand and power plant generation rates in Maryland are traditionally highest in the summer months.

Nitrogen Oxides (NO_x)

The entire State of maryland is in compliance with NAAQS for nitrogen oxides (25). Figure III-17 shows that the annual average ground-level concentration of NO_2 has remained relatively constant in Maryland from 1974 to 1979 (2).

Photochemical Oxidants and Hydrocarbons

All of Maryland is in attainment for ozone, except for sections of Baltimore City, Washington County, and the Washington, DC area. Previous nonattainment areas in Garrett and Allegany counties are now unclassified or have ambient levels lower than national standards (25, 26).

F. Pollution Control

Ambient air quality can be improved by reducing emissions of pollutants from power plants (via emission control, conservation, cleaner fuel, or alternative power sources such as solar or nuclear) or by enhancing dispersion. The need for emission control can be assessed by comparing uncontrolled emission factors to allowable emissions under new Source Performance Standards. Table III-6 relates NSPS to the emissions resulting from burning coal, oil, or gas without any emission control. The NO_2 standard set by NSPS can be met by controlling the combustion process in the power plant boiler.

Table III-6 shows that natural gas is the only fuel with particulate emissions low enough to meet NSPS without additional particulate emission controls. Plants burning coal with an ash content of 15 percent would need precipitators with an efficiency of about 99.7 percent. Although modern precipitator technology now permits efficiencies exceeding 99 percent (31), actual performance is often critically dependent on fly ash composition, sulfur content, and equipment maintenance, and must be carefully monitored.

Particulate emissions also result from coal delivery, storage, conveying, and sizing for optimum combustion, and from transfer of fly ash and bottom ash from control devices and boilers. Such emissions are termed "fugitive" (i.e., they do not emanate from a stack or vent).

Power plants located in the Baltimore and Washington, D.C., metropolitan areas are required to apply reasonable available control measures to abate fugitive emissions. Such measures might include unloading coal cars in an enclosure equipped with water sprays, enclosing conveyors, and equipping

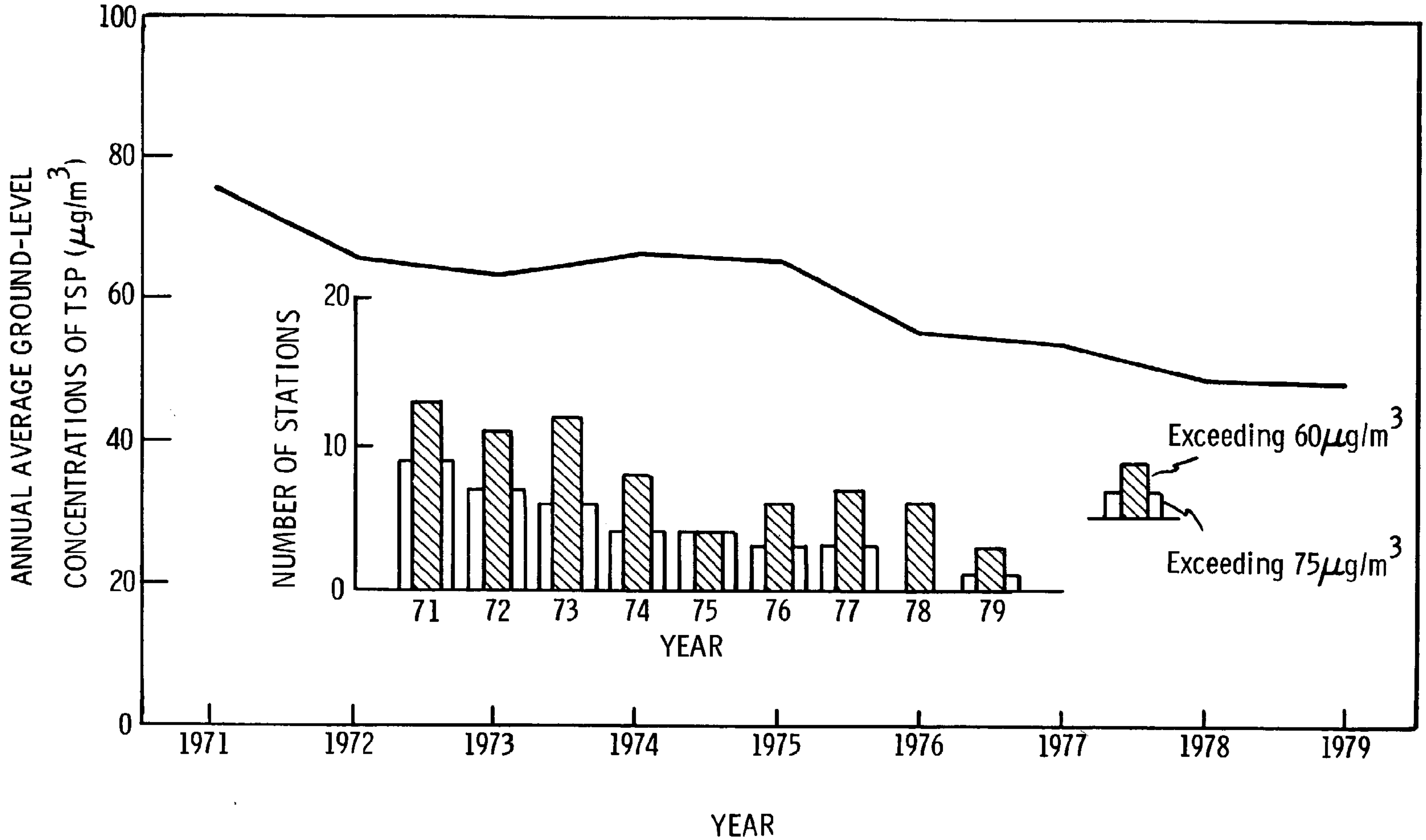

Figure III-13. Composite means of annual average TSP ground-level concentration at 21 stations throughout Maryland which have a continuous record since 1971. Violations of primary and secondary TSP NAAQS for the same 21 stations. Based on Ref. 2.

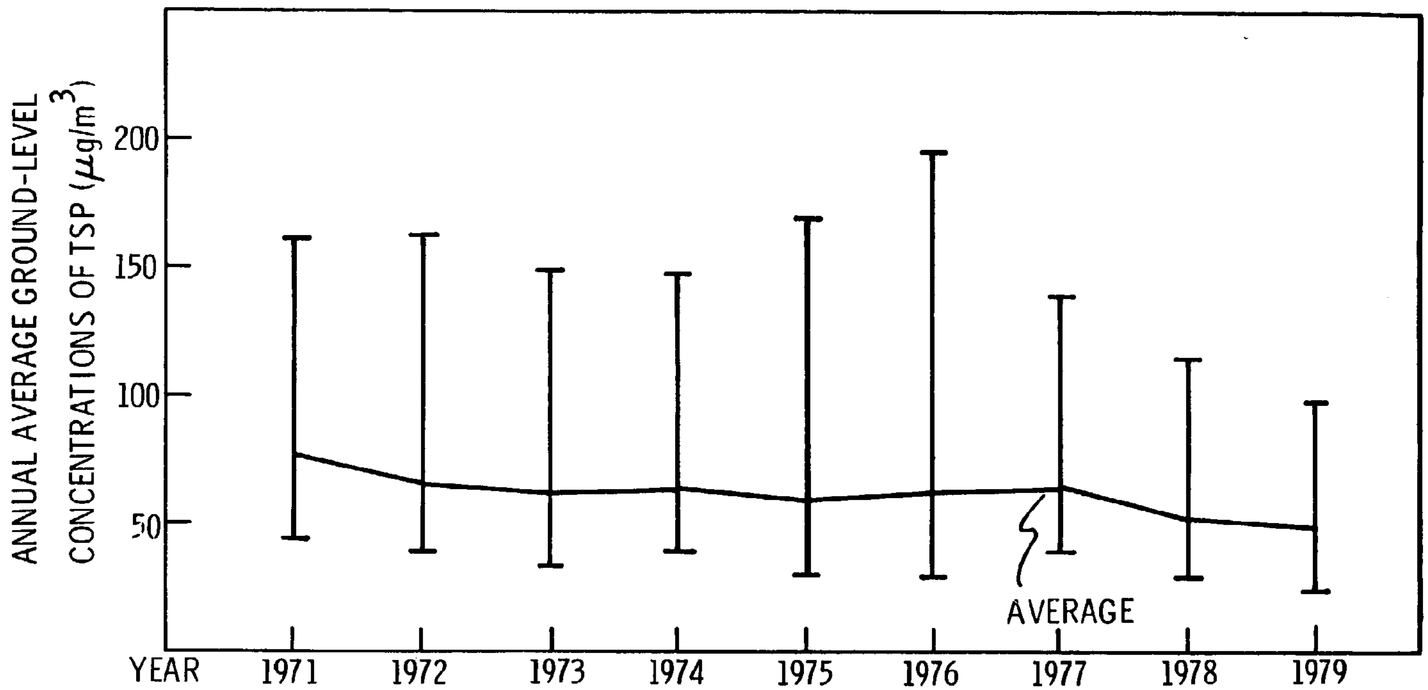

Figure III-14. Composite mean of the annual average TSP ground-level concentration for all Maryland stations with adequate data (at least 75% of the prescribed number of readings). The bars indicate the range of values. Based on Ref. 2.

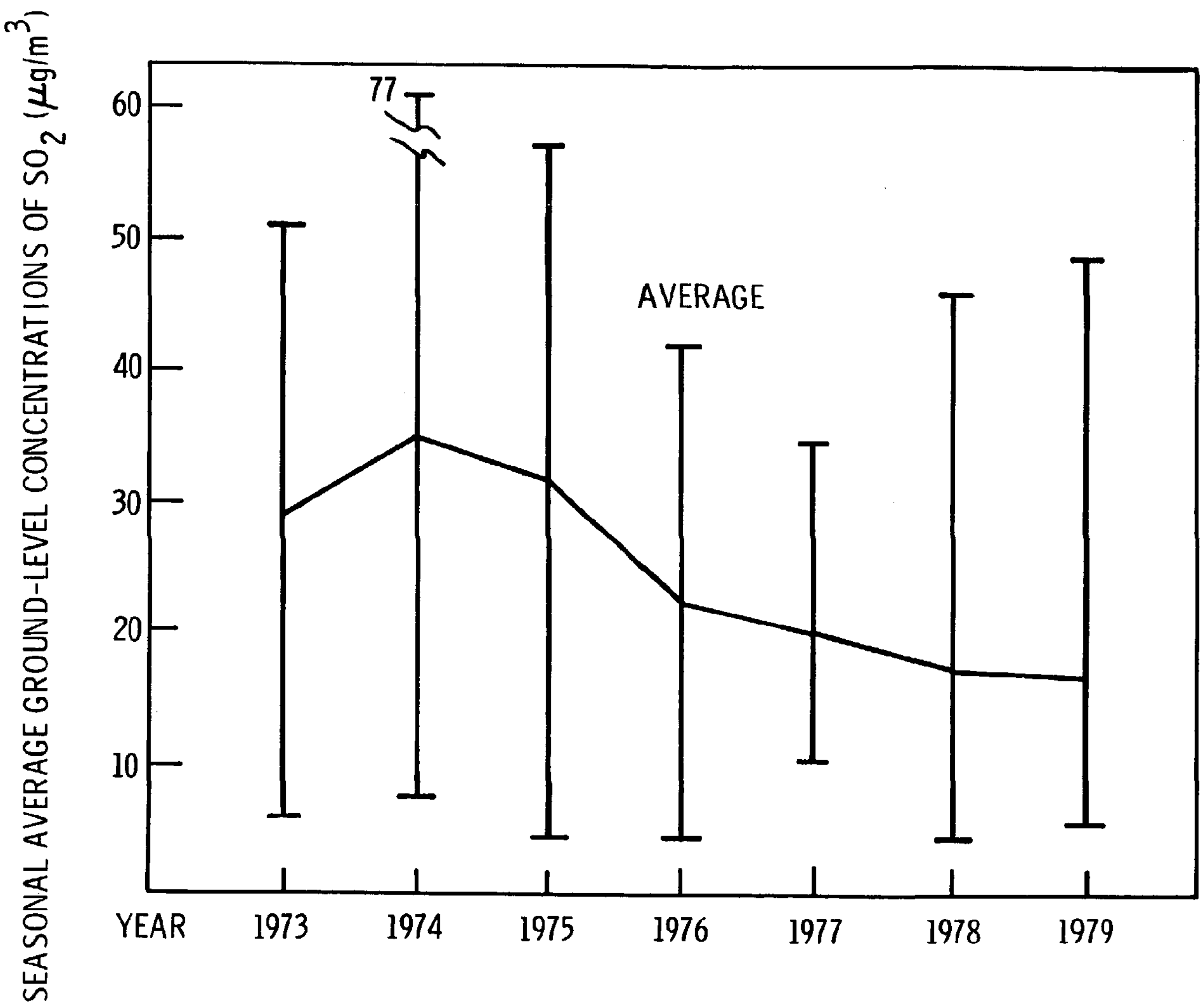

Figure III-15. Composite mean of annual SO_2 ground-level concentrations average for those Maryland stations with data for the entire year. For informational purposes only; many stations have less than 75% of the prescribed number of readings. Measurements are by the flame photometric method. Range of values is indicated by the bars. Based on Ref. 2.

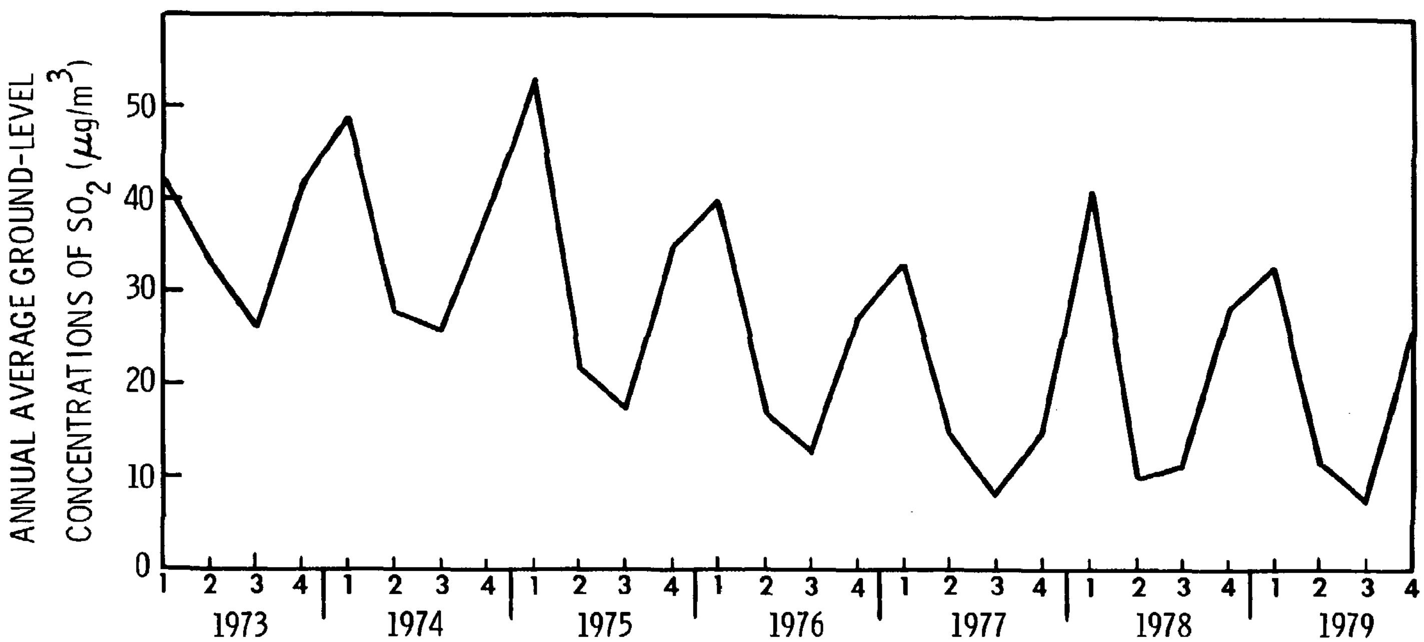

Figure III-16. Seasonal trend in SO_2 ground-level concentrations, average for all Maryland stations (flame photometric method). For informational purposes only; many stations have less than 75% of the prescribed number of readings. Based on Ref. 2.

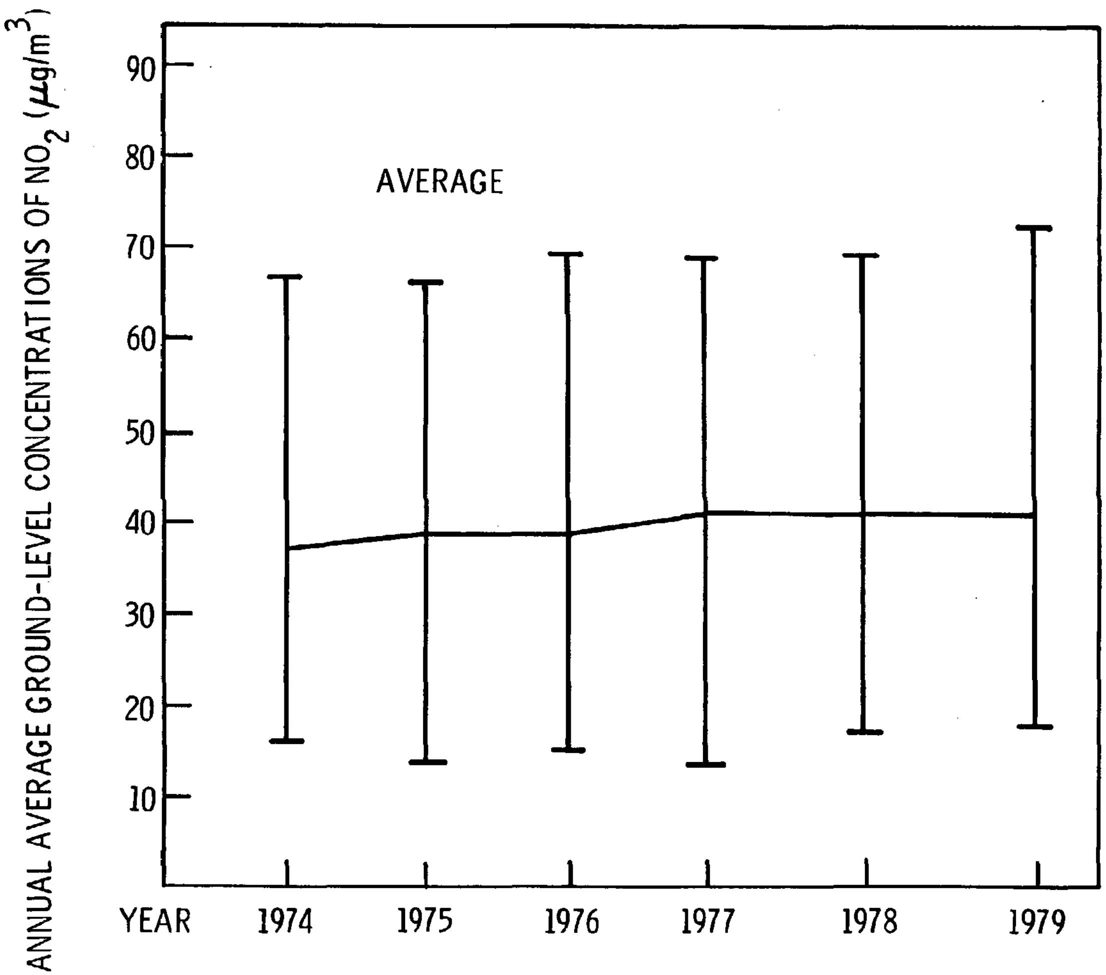

Figure III-17. Composite mean of annual average NO_2 ground-level concentrations (measured by 24-hr gas bubbler) for all Maryland stations with adequate data (at least 75% of the readings). Range of values is indicated by bar. Based on Ref. 2.

Table III-6. Comparison of New Source Performance Standards (NSPS) and Emission Factors for Combustion in Utility Boilers

POLLUTANT: FOSSIL FUEL AND FURNACE TYPE	PARTICULATE MATTER: STANDARD ($lb/10^6$ Btu) Old	New	EMISSION[(a)] FACTOR	SULFUR DIOXIDE: STANDARD ($lb/10^6$ Btu) Old	New[(b)]	EMISSION[(a)] FACTOR	NITROGEN DIOXIDE: STANDARD ($lb/10^6$ Btu) Old	New	EMISSION[(a)] FACTOR
Pulverized Coal	0.10	0.03		1.2	1.2		0.70	0.60[(c)] (0.50)	
General			0.67A			1.58S			0.75
Wet bottom			0.54A						1.25
Dry bottom			0.71A						0.75
Cyclone			0.08A						2.29
Fuel Oil	0.10	0.03		0.80	0.80		0.30	0.30	
Tangentially fired			0.055			1.08S			0.34
Other									0.72
Natural Gas	0.10	0.03		No std.	0.80		0.20	0.20	
Tangentially fired			0.014			0.00055			0.27
Other									0.64

Note: The old standards did not apply to lignite.

(a) A is ash content of coal in percent by weight. S is sulfur content in percent by weight. Emission factors have been converted from weight and volume units to Btu's using the following conversion, which approximates conditions prevailing in Maryland:

Coal: 12,000 Btu/lb = 24 x 10^6 Btu/ton
Oil : 145,000 Btu/gal = 145 x 10^6 Btu/thousand gals
Gas : 1,100 Btu/ft^3 = 1,100 x 10^6 Btu/million ft^3

Emission factors are only approximate guidelines and may be conservative (high). The emission factor of 1.58S for sulfur dioxide assumes that 95 percent (by weight) of the sulfur in the coal is released as sulfur dioxide (3).

(b) The new NSPS also require a 90 percent reduction (presumably by scrubbing) of the uncontrolled SO_2 emissions from solid, liquid, and gaseous fuels. An 85% reduction is required when solvent refined coal is used. For sources emitting less than 0.6 lb SO_2 per million Btu, the percent reduction required is 70%. No reduction is required when the facility uses liquid or gaseous fuel and emits less than 0.2 lb SO_2 per million Btu.

(c) The new NO_x coal standard of 0.60 applies to bituminous coal, and 0.50 applies to subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal.

transfer points with water sprays; equipping screens and crushers with water sprays, at the inlet and outlet, periodically applying a crusting agent to inactive storage piles; handling fly ash in enclosed systems; and storing fly ash in fabric-filtered bins prior to disposal.

Under the provisions of Prevention of Significant Deterioration (PSD) regulations, new power plants are required to apply Best Available Control Technology for stack and fugitive emissions. For these plants, the previously discussed control measures would be the minimum required, no matter where the plant is located in Maryland.

The old (1971) NSPS could be met through use of clean (or cleaned) fuels. For example, control of SO_2 emissions was not needed for gas. Oil could meet the old and new emission standards, provided that the sulfur content was about 0.8 percent or lower. Attainment of this sulfur level presents no technical problem, although there may be a related economic penalty (see Table III-7). SO_2 emission control for coal-burning power plants could potentially be achieved by:

- Use of coal of inherently low sulfur content (less than 0.8 percent)

- Conversion of coal to cleaner fuels

- Use of advanced combustion systems (fluidized-bed combustion).

Extensive research programs funded by private and public interests are underway in these areas. The requirement of the new (1978) NSPS that almost all power plant effluents must be scrubbed to reduce SO_2 may remove much of the economic incentive for development of these technologies, although some credit will be given for precleaning fuel. The advanced technologies will probably be commerically available for power plant operations in the late 80's (32). Many of these technologies are not complicated for small-scale uses but are difficult to transfer to the large scale of a power plant. See the 1978 CEIR (14) for a review of these programs.

G. Mathematical Modeling

Mathematical modeling is becoming increasingly important for predicting air quality impacts caused by present and future sources. Section 320 of the 1977 Amendments to the Clean Air Act (33) recognizes modeling as a necessary tool, especially for predicting the extent of increment consumption by proposed sources and modifications subject to PSD.

The most widely favored dispersion models are based on the concept of the Gaussian plume. These models assume that the pollutants are dispersed by the wind such that the average concentrations across the plume (i.e., perpendicular to the mean wind direction) are distributed as the bell-shaped normal (or Gaussian) curve. Both vertical and horizontal dispersion are assumed to have this form although their widths generally are different. The plume centerline will rise to a height determined by the buoyancy of the effluent gasses.

The Gaussian formulation is attractive because it is simple -- the basic equations can be evaluated with a hand calculator. It is also applicable to a wide variety of physical conditions. The ground-level concentration (GLC)

Table III-7. Fuel Costs for Maryland Utilities (1980 Prices, in Dollars).

Utility Steam Coal

Percentage Sulfur	Costs		Differential	
	Cost per ton	Cost per 10^6 Btu	Per ton	Per 10^6 Btu
0.5 - 1.0	44.31	1.73	Base	
1.5 - 2.0	37.22	1.57	7.09	0.16
2.0 - 3.0	37.98	1.55	6.33	0.18
> 3.0	19.66	0.90	24.65	0.83

Residual Oil

Percentage Sulfur	Costs		Differential	
	Cost per Barrel	Cost per 10^6 Btu	Per Barrel	Per 10^6 Btu
0.5 - 1.0	27.32	4.38	Base	
1.0 - 2.0	25.18	4.03	2.14	0.35
2.0 - 3.0	22.54	3.62	4.78	0.76

Data based on Reference 52.

for a variety of pollutants may be projected for a number of wind conditions and atmospheric stabilities and averaged over sets of meteorological conditions. Various additional computations can and have been built into specific models to simulate the effects of momentum-dominated plume rise, chemical reactions and ground deposition (which are especially important in long-range plume transport), building interference, impact of terrain features, etc. Because the selection of such options may drastically change the projected GLCs, the EPA has recently issued guidelines designed to improve the uniformity of model applications. Some of the models that have recently been accepted as "guideline" models are CRSTER (a single point-source model for use in rolling terrain), RAM (a multiple-point and-area source model used in urban areas), and ISC (an industrial source complex model containing provisions for modeling multiple-point, -volume, and -area sources).

Because the results from these models determine regulatory requirements for many projects, it is important that these projections be accurate. Underestimates of GLCs may lead to inadequate protection of public health and welfare, while overestimates of GLCs will result in installation of unnecessarily expensive emission control equipment. Because of the assumptions of Gaussian distribution, the empirical nature of the coefficients used, and the vagaries of real atmospheres, these models frequently project GLCs that disagree with measured values by more than a factor of two (34).

Research is therefore continuing at a variety of public and private installations to improve these models and develop additional types that may provide more reliable projections than the conventional Gaussian formulation. These new models emphasize better characterization of the ambient flow fields, both mean and turbulent, into which pollutants are emitted, although the models often still rely on a Gaussian distribution within the plume. Also, in recent years, the question of fugitive dusts has become a major air quality consideration. No model have been validated (proved acceptable) for estimating impacts of fugitive dusts at nearby downwind receptors. Hence, considerable work is being done to develop models that can be used to estimate emissions and dispersion of fugitive dusts from material storage piles under a variety of wind conditions.

Current models are also deficient in accurately describing plume transport and dispersion in complex terrain. In recent studies, the flow field about the terrain has been modeled with simple potential flow methods for neutral stability (35) or similarly simple approaches (35, 36) for stable conditions and certain types of terrain. The flow fields are used to locate the plume centerline within the flow while the pollutant distribution about the centerline is still assumed to be Gaussian. Summaries of ongoing large-scale field programs pertaining to complex terrain problems can be found in References (37) and (38).

Work is also continuing on modeling the effects of enhanced turbulence in building wakes on plume diffusion within such wakes. Although the Gaussian formulation is used, the height of the plume centerline is sometimes decreased, and the dispersion parameters are increased by an amount depending on building size, geometry, and downwind distance. These modifications depend strongly on the results of wind-tunnel simulations, and field confirmation is still needed. A recent review of these approaches is given in Reference (39).

An example of improved modeling of flow fields where the Gaussian formulation is not retained, is the calculation of pollutant dispersion during convectively unstable conditions within a region of limited vertical extent (the mixing depth). It is under these meteorological conditions that tall stacks in flat terrain usually produce their highest ground-level concentrations. Recent laboratory experiments (40) and numerical simulations (41) of pollutant dispersion in convective conditions show that the vertical distribution of pollutants is not Gaussian. This deviation is attributed to the characteristics of the thermal velocity field -- updrafts and downdrafts -- which distribute the pllutants. The findings from these detailed research studies (40. 41) have led to simpler models for stack plume dispersion during convective conditions (42, 43).

H. Regulatory Effects

The Clean Air Act Amendments of 1977 are of major importance in the regulation of air quality in two crticial areas: 1) they specify acceptable approaches in controlling atmospheric emissions from industry; and 2) they give specific legislative direction to "prevention of significant deterioration", one of the most controversial concepts of air pollution control.

Some of the most signinificant provisions related to power plant siting and operations are discussed below. The Clean Air Act is scheduled for congressional review during 1982. Some of the provisions described here may be changed at that time.

Stack Height and Intermittent Control

In response to the Clean Air Act Amendments of 1977, which called for reductions in pollutants, some electric utilities sought simply to decrease the GLC of the pollutant in the air shed rather than reduce the actual amounts limited. Three methods were proposed: 1) the use of very tall stacks, 2) switching of fuel, and 3) switching of load between plants. The EPA argued against the acceptability of these methods because they did not diminish emissions. Although better air quality, as defined by GLC, was atained by spreading the pollutants, the improvement was an artifact.

The new Act essentially eliminated the use of these dispersion methods by denying credit for pollution abatement attributed to them. This approach was recently upheld in the case of Dow vs EPA in the U.S. Court of Appeals for the 6th Circuit. In particular, credit is denied for stack height exceeding "good engineering practices", which is "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash eddies and wakes which may be created by the source itself, nearby structures or nearby terrain obstacles" (33). Proposed EPA regulations pertaining to tall stacks (44) set the height for good engineering practice (GEP) as the height of the structure plus 1.5 times the lesser of the height or width of the structure. "Nearby" (Section 123) is taken to be a distance up to five times the height or width of the structure, but not more than 0.5 miles (0.8 km) away unless a greater height is necessary to avoid the excessive concentrations referred to above. Typically, the GEP stack height of a power plant is 500 to 600 feet.

Nonattainment Areas

When air quality in a region does not meet National Ambient Air Quality Standards, the area becomes "nonattainment", and no further increase in total pollutant emissions from major sources in the area is allowed. To permit new industries to locate in such regions, the EPA has promulgated a policy of "emission offsets" (38). The policy states that a new power plant to be located in such a region must not only meet an emission limitation specified as the Lowest Achievable Emission Rate (LAER) for that source, but must also provide for sufficient reduction of emissions from its own or other sources in the area to offset the new emissions. The objective is to achieve "reasonable progress toward attainment of the applicable NAAQS." Any power plant outside the nonattainment region producing a "significant" degradation in the air quality of the nonattaniment region is also subject to an offset requirement.

Although the intent of this policy is to satisfy the competing needs of growth and maintenance of air quality, it engenders several significant consequences. First, it appears to give industries now emitting major amounts of pollutants the power to sell "pollution rights". That is, they could sell the right to clean up their output levels to the highest bidder. As a result, one company can be economically responsible for the operation and maintenance of another company's pollution controls. In fact, the new source, rather than the sources already located in the area, would be forced to bear the economic burden of controls both for its own plant and the offset plants. Thus, unless there are compelling economic considerations for locating in a particular region, plant owners will tend to choose sites where they will not be subject to an offset.

The State of Maryland is presently encouraging the development of an "offsets market" for the Baltimore nonattainment area. The first agreement of this nature was recently established between Maryland Slag, Bethlehem Steel, and Atlantic Cement Company. Under the agreement, Maryland Slag will sell emission offsets to Atlantic Cement so that Atlantic can process slag from Bethlehem Steel. Bethlehem will reduce emissions from open storage piles to provide additional required offsets. The air quality analysis that provided the basis for the trade-off was facilitated by the close proximity of the three companies.

Maryland presently has nonattainment areas for three pollutants: particulates (Baltimore area), carbon monoxide (Baltimore and Western Maryland), and photochemical oxidants (Baltimore, Washington D.C., and scattered areas elsewhere).

The Baltimore TSP nonattainment area is the one which affects power plants most. Recent analyses indicate that up to 70 percent of the total blowing dust there is due to fugitive emissions. The recently submitted Maryland SIP revisions (45) propose paving roads and covering storage piles in the nonattainment region to reduce blowing dust. In addition, power plants converting to coal contributing more than 5 $\mu g/m^3$ (24-hour) or 1 $\mu g/m^3$ (annual) in this region will be a subject to stringent fugitive emission controls and may be required to obtain emission offsets. These requirements will particularly affect the design of coal-handling facilities at plants undergoing coal conversion.

To estimate the implications of this policy for siting new power plants near such areas, a typical 1,000-MW coal-fired station was modeled. It was assumed that emissions were at the levels permitted by the New Source Performance Standards (Table III-5). The results indicated that, to avoid an offset, such a plant could be located no nearer than 10 to 15 miles from the border of a nonattainment area, depending upon the local meteorology.

Thus, the siting of future fossil-fueld power plants in Maryland will be influenced to a large extent by the existing TSP nonattainment areas.

Prevention of Significant Deterioration (PSD)

The most significant change within the Clean Air Act relates to PSD (46, 47). The law establishes upper limits on allowable air quality changes for SO_2 and particulates. It designates three classes of areas (I, II, and III) with differing restrictions on increases in pollution levels.

The Class I area designation is reserved for regions where it is desirable to maintain the present air quality. Automatically classified within this category are international parks, national wilderness and memorial parks over 5,000 acres, and national parks over 6,000 acres. Other areas may be added to this list by the State, in some cases at the suggestion of the Federal Land Manager. Maryland has no Class I areas at this time, although there are several such areas in nearbly Virginia and West Virginia (see Fig. III-18).

Class II areas are assigned allowable increments that permit moderate industrial growth. All areas of the country not originally classified as Class I start out in this category.

Class III areas are less restricted and may allow fuller industrial development. A Class II area may be redesignated Class III only after a process involving the Governor, the legislature, and "general purpose units of local governments." The actual procedure is not determined at this time.

The allowed increase (increments) for each area and the comparable standards are shown in Table III-2. The total increments used by all emitters must stay within the specified limits.

According to the Clean Air Act Amendments of 1977, Sec. 163 (a):

> "In the case of sulfur oxides and particulates, each applicable implementation plan shall contain measures assuring that maximum allowable increases over baseline concentrations of, and maximum allowable concentrations, such pollutants shall not be exceeded. In the case of any maximum allowable increase (except an allowable increase specified under 165 (d) (2) (C) (iv) for a pollutant based on concentrations permitted under national ambient air

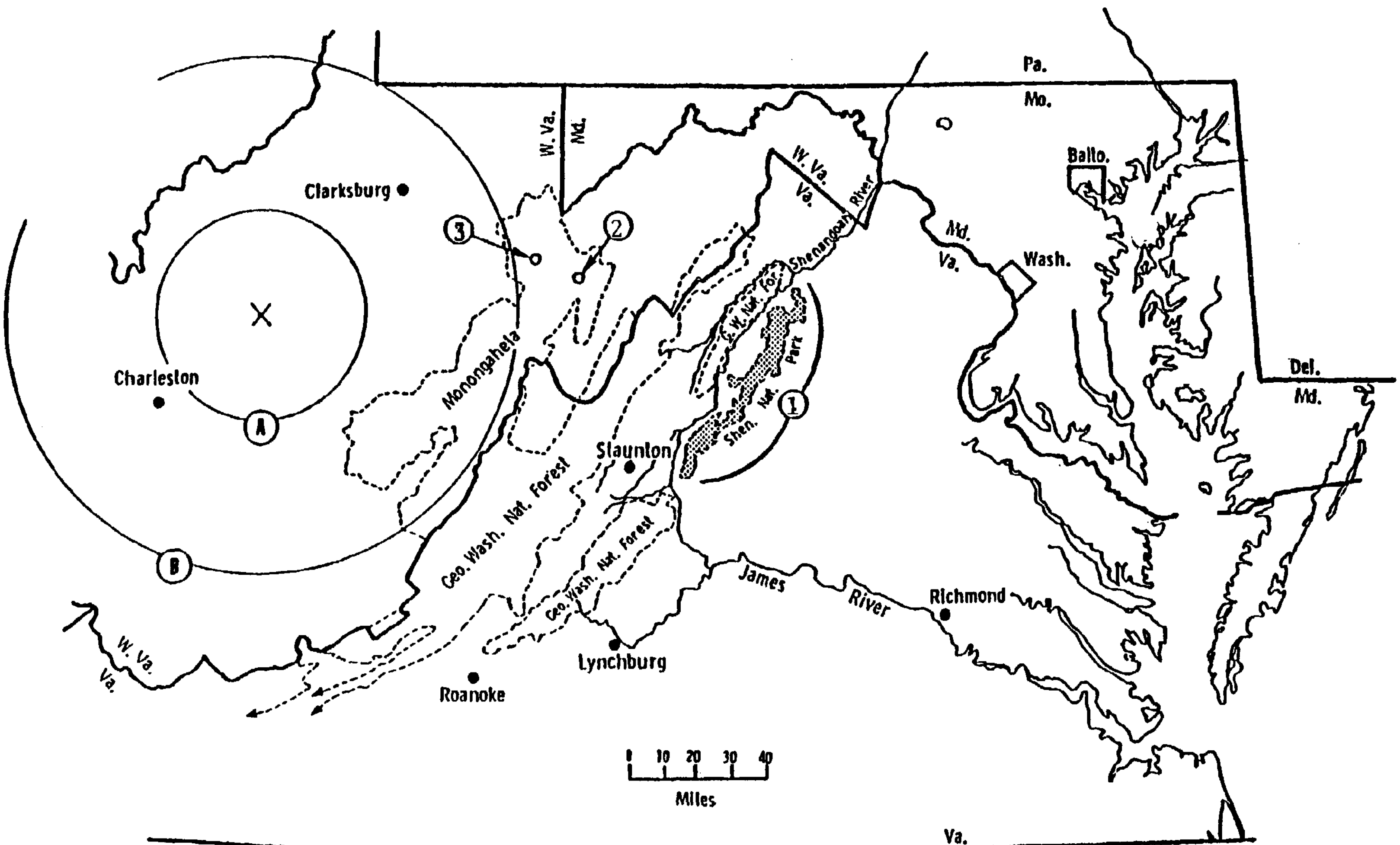

Figure III-18. Mandatory Class I areas around Maryland. There are no mandatory areas in Pennsylvania.

1) Shenandoah National Park
2) Dolly Sods
3) Otter Creek

Circle A shows the Class I exclusion area for a hypothetical 1000-MW power plant located at X burning 1% sulfur coal with an 80%-efficient scrubber; circle B shows the exclusion area for the same plant burning 2% sulfur coal.

quality standards for any period other than an annual period, such regulations shall permit such maximum allowable increase to be exceeded during one such period per year."

This section clearly indicates that the total GLC (from all sources) should be considered in a before-and-after analysis. Certainly, if no changes have been made in the sources before and after, no PSD increment should be consumed. Therefore, to conduct such an analysis, the same meterological data must be used for both "before" and "after".

The annual average PSD increment can be calculated for each receptor point by calculating the annual averages due to only the changes (plus and minus) in emissions at the sources. This simple procedure can be used for calculating the annual PSD increment consumption because source contributions to the annual average GLCs are additive. The maximum annual PSD increment consumed is then the greatest of the calculated increments for the set of receptors. This maximum is usually less than the sum of the maxima (at the respective maximum locations) for individual source alternations.

The 24-hr. PSD increment consumption is more difficult to model. The PSD increment consumed at each receptor is obtained by calculating the highest (or second-highest) 24-hr. GLC due to all sources after the change and subtracting from these values the highest (or second-highest) modeled "baseline" 24-hr. GLC at that receptor. The maximum 24-hr. PSD increment consumed is then the greatest of the calculated increments for any receptors in the set. Because GLCs depend strongly on wind speed and direction, the 24-hr. PSD increments consumed at any receptor can be less than the total PSD increments consumed due to a number of changes at the various individual sources, even when measured at the same receptor.

To aid the U.S. in becoming less dependent on foreign oil, EPA has allowed a temporary suspension of PSD provisions for power plants that may be ordered to revert to coal under provisions of the Energy Supply and Environmental Coordination Act of 1974. These reversions are exempt from the requirements of NSPS and not subject to PSD review. However, where allowable PSD increments are exceeded due to coal burning the State will be required after 5 years to obtain emission reductions at other installations sufficient to restore the increment to the allowable limit.

Since pollutants may travel across political boundaries, the question arises of what disposition to make in cases where long-range transport of pollutants from a large coal-fired plant in, for example, Ohio or West Virginia consumes part of the available PSD increment for neighboring states. By federal regulation, the maximum allowable consumption by an out-of-state utility is 50 percent of the remaining increment. However, this amount may not be acceptable to the affected state. It is not clear at this time what recourse a state so affected would have, especially if the additonal pollutants do not cause a violation of standards. The present amendments (Section 126) call only for "written notice to all nearby states. . . at least sixty days prior to the date on which commencement of construction is to be permitted."

PSD analysis requirements also include an estimation of SO_2 and TSP transport into distant Class I areas, and the results are relevant for siting decisions. This analysis is difficult since 1) the Gaussian plume model is not accurate at distances beyond 20-30 miles, 2) the meteorological data necessary for realistic calculations (vertical profiles of wind every 20-30 miles) are not available, and 3) the interaction of pollutant plumes from various sources is not well understood. Typical "exclusion distances" for a 1000-MW power plant operating at normal fuel consumption (2% S coal and 90% flue gas desulfurization) would be 30-70 km.

Coal Conversion

At one time, virtually all of the power plants in Maryland were coal-fired. Because of stringent pollution control requirements and lower cost, many of these plants were converted to oil in the late 1960's or early 70's. However, reconversion to coal is now being considered in response to the current oil supply and price situation.

At the present time, eight units -- Crane 1 and 2, Brandon Shores 1 and 2, Wagner 1 and 2, and Riverside 4 and 5 -- are under "prohibition orders" issued under the Energy Supply and Conservation Act (ESCA) and the Fuel Use Act (FUA). Should these orders be made final, these facilities will be prohibitied from burning oil or gas. The environmental consequences of these conversions need to be carefully examined: six of the eight units are located in, or nearby, an area that does not presently meet standards for particulates. Fueling with coal also will generally increase SO_2 ground-level concentrations and consume PSD increments.

Baltimore Gas and Electric Company has voluntarily applied to the Maryland Public Service Commission for conversion of the Brandon Shores and Crane plants to coal. (PSC cases #6516 and #7443, respectively). Final briefs have been filed for Crane and Brandon Shores (48, 49, 50). General agreement has been reached on the equipment and fuel necessary to control particulate and sulfur oxide emissions to permissible levels.

Of the two remaining plants, only conversion at Wagner appears economically sound. Riverside is relatively old (29-30 years), has a low capacity factor, and is subject to severe space and environmental limitations. Wagner Units 1 and 2, on the other hand, are younger (21-24 years), have a higher capacity factor, and already have coal facilities in use for Unit 3. Rough estimates of cost savings due to fuel conversion indicate a payback period of 1-2 years. Thus, it is likely that Wagner Units 1 and 2 will be ordered to burn coal.

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CHAPTER IV

AQUATIC IMPACT

For each kilowatt hour of electricity generated, a steam power plant burning fossil fuel must dispose of about 4,400 Btu of heat via its condenser, and a nuclear power plant must dispose of about 6,600 Btu. Most Maryland power plants use once-through cooling systems to transport this waste heat from the plant. In these systems, water is drawn into the plant, heated 10 to 17°F in the condenser, and discharged into a receiving body of water. Approximately one million gallons of water per minute (or 63 m^3/s) is required for each 1,000 MW of generating capacity. Closed-cycle cooling can be used to reduce water withdrawal. Use of this technology will allow consideration of such options as more power generation per site, or sites in more sensitive areas.

The Chesapeake Bay and its tributaries serve as the major source of cooling water in Maryland. At the same time, this ecological system supports complex aquatic food webs that produce renewable resources of fish and shellfish. A major concern of the Power Plant Siting Program is to ensure that power plants provide electricity at a reasonable cost, while not interfering with the maintenance of sustained yields of these resources and the stability of the system, which depends on all components of the food web. Thus, the impact of power plants on the aquatic ecosystem as a whole must be evaluated, and measures to mitigate this impact should be examined for their potential benefits and costs.

A. Sources and Nature of Impact

As water is drawn through a power plant and returned to its source, aquatic organisms interact with cooling system structures, intake and discharge velocity fields, the heated effluent, antifoulants, and other alterations of the environment caused by plant operations, as explained below.[1] The locations and nature of the interactions and ensuing stresses which are encountered by aquatic organisms are briefly described below: (See also Figure IV-1)

- Entrapment

  Two of the largest Maryland power plants (Calvert Cliffs and Morgantown) have intake embayments partially shut off from the main bay or river by a curtain wall, i.e., a wall reaching from above the surface of the water to some depth below the surface. The function of the curtain wall is to permit the plant to draw its cooling water from the deeper portions of the water column, where temperatures tend to be lower than at the surface during summer months. During the summer, large numbers of fish congregate in the intake embayments and may be entrapped there. During the summer months, dissolved oxygen (DO) concentrations in the water often drop to levels below that needed to sustain adult and

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[1]Radiological effects are discussed in Chapter V.

juvenile fish. The drop is pronounced in the deeper water entering the embayment under the curtain wall. Fish kills may result. The killed (or weakened) fish may then impinge in large numbers on the protective intake screens. In the following discussions entrapment will not be treated as a separate effect.

- Impingement

The circulating pumps for the cooling water are protected by intake screens (usually 3/8-inch mesh). Organisms too large to pass through these screens may be impinged, i.e., pinned against them by the pressure of the passing water, a prospect that is markedly increased when the organisms (fish or crabs) are weakened by stresses such as low DO conditions. The screens are rotated periodically and the impinged matter is washed off. At several plants the organisms are flushed back into the cooling stream discharge. Some species survive this treatment, but others suffer a high rate of mortality.

- Entrainment

Organisms small enough to go through the intake screens pass through the entire cooling system, where they are stressed by mechanical forces due to physical contact with pumps and pipes, and pressure and shear forces generated by complex flow patterns and turbulence.

While passing through the condenser, the entrained biota will be subjected to a sudden temperature rise. The biological response to this heating depends on the magnitude of the temperature rise, the length of exposure to the elevated temperature, and the initial ambient temperature. In Maryland plants, the temperature rise varies from 10^{o} to $32^{o}F$ and the exposure time from a few minutes to almost two hours (including retention time in effluent canals). Thus, " thermal stress dose," i.e., a product of temperature and time, is quite variable.

Entrained biota experience additional stress at plants where biocide (usually chlorine) is added to the cooling water to prevent clogging of the cooling system by biomass build-up.

- Discharge Effects

The alteration of local habitat produced by the discharge of cooling water can manifest itself in several ways. Aquatic organisms can be "entrained" into the discharge plume, where they will be exposed to higher-than-ambient temperatures and biocide residuals. Other toxic substances released with the cooling water (e.g., copper) may affect the stationary benthic communities near the plume. Finally, a fast-moving discharge flow may alter the characteristics of bottom sediment in its way and may also directly influence the behavior of some organisms in the discharge zone.

Plants using cooling towers rather than once through cooling systems exert similar stresses on organisms interacting with them. However, the degree of stress,in most cases, differs markedly between the two types of

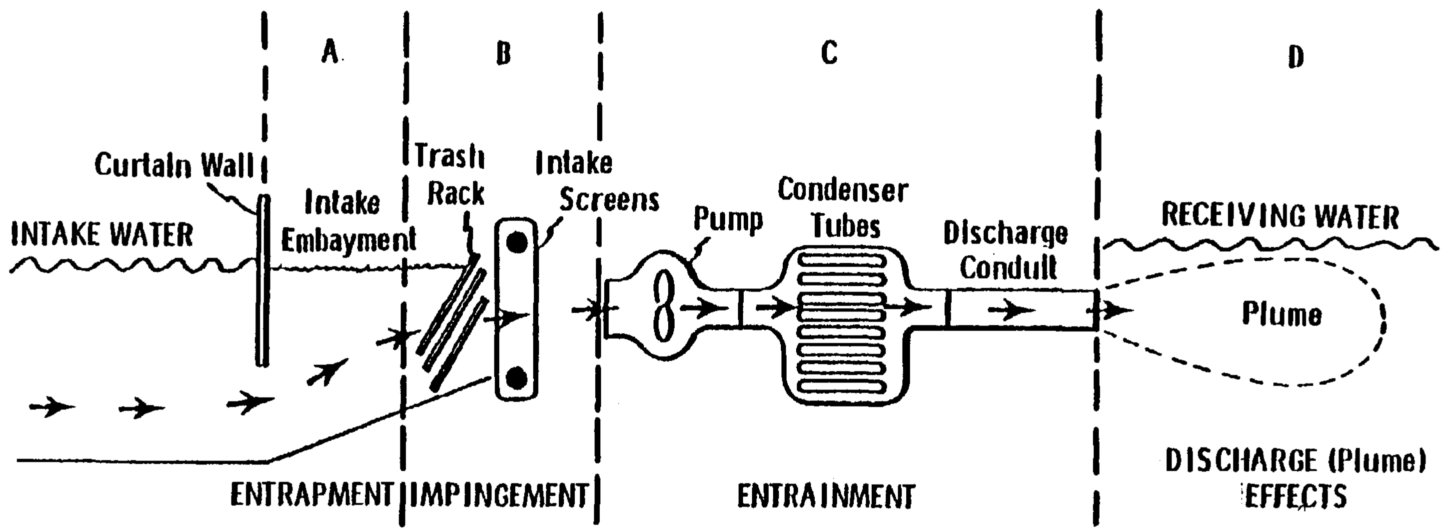

Figure IV-1. Path of water flow through a power plant using once-through cooling and locations of plant-organism interactions.

A. Fish may be entrapped in the intake embayment and may suffer prolonged exposure to water of low dissolved oxygen content drawn from below the curtain wall.

B. Organisms may be trapped on intake screens; the screens are rotated to wash fish and crabs from the screens back into the receiving water.

C. Small organisms in the water column (plankton) pass through the cooling system; they experience a temperature rise and also shear and pressure forces during their transit through the cooling system.

D. Organisms in the receiving water may encounter temperature rises in the plume (plume entrainment) and may be affected by the discharge.

cooling system. The volume of water withdrawn for use in cooling towers is small and intake velocities are low; the result is that entrapment and impingement tend to occur at low rates. The numbers of organisms entrained are low, but mortality is essentially 100 percent because residence time of water in cooling towers is very high. Cooling towers discharge a portion of their cooling water on a regular basis; this water is known as blowdown. Blowdown often contains high levels of metals such as copper (eroded from the cooling system pipes) and biocides, used to prevent fouling of the system. In saline waters, blowdown may also have a high salinity, due to evaporation. Discharge effects due to blowdown release will be similar to that from a once-through cooling system, but because of the small water volumes involved, the area experiencing discharge effects would be very small. For cooling towers the consumptive use of water can often be a concern, requiring augmentation reservoirs to make up for evaporative losses during low-flow conditions in the source waters.

The organisms interacting with the power plant can be grouped as follows:

- Phytoplankton
- Zooplankton
- Benthos
- Ichthyoplankton
- Juvenile and adult fish and crabs.

Individual groups may be more susceptible to damage by one type of power plant interaction than by another (Table IV-1). Entrapment most often stresses juvenile fish. Impingement stresses adult and juvenile fish and crabs. Entrainment stresses planktonic organisms (which serve as food for many resource species), as well as the planktonic larval stages of many resource and forage species. All aquatic biota may experience discharge effects, but benthic species, because of their predominantly immobile life style, would be most stressed.

Mortalities resulting from plant/organism interactions can cause a decline in a population if they are not offset by biological compensation mechanisms such as increases in growth rate, fecundity, recruitment and/or early survival. In the case of phytoplankton or zooplankton, losses due to entrainment are generally recouped quickly as a result of inherent rapid reproduction rates (generation times of hours to days). Other organisms have much longer generation times. Most fish spawn only once a year and may not reproduce until several years of age. For species utilizing a very localized spawning or nursery area adjacent to a power plant, high entrainment losses can occur unless cooling towers with carefully controlled blowdown are used to reduce the amount of organisms entrained. The potential for such losses having an impact is much less for ubiquitous species which spawn in or inhabit wide areas of the Bay.

Table IV-1. Major Types of Aquatic Effects of Power Plant Operations.

Sources of Effects	Primary Susceptible Organisms	Type of Stress				
		Low DO[a]	Mechanical	Thermal	Chemical	Habitat Alteration
Entrapment	Adult and juvenile fish	x	-	-	-	-
Impingement	Juvenile fish, crabs	-	x	-	-	-
Entrainment	Ichthyoplankton[b] Zooplankton[c] Phytoplankton[d]	-	x	x	x	-
Discharge	Adult and juvenile fish, benthos[e], shellfish	-	-	x	x	x

[a] Low dissolved oxygen concentrations -- oxygen deficiency

[b] Eggs and larvae of fish

[c] Weak swimming animals present in the water

[d] Minute plants present in the water

[e] Organisms living in or on the bottom.

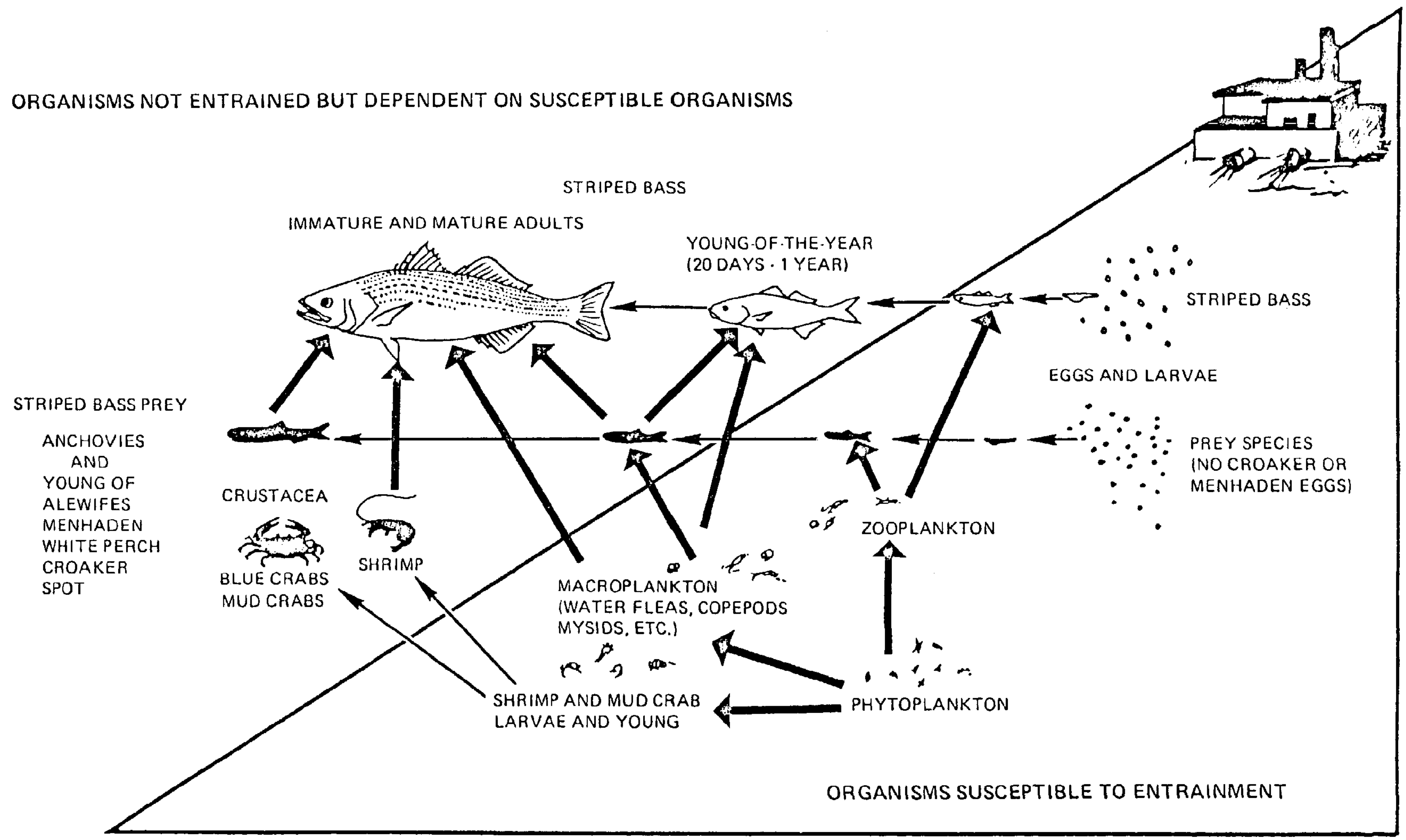

Fig. IV-2. Areas of potential power plant entrainment impact on striped bass and associated food items.

Plant operations can indirectly cause a decline of a population by decreasing the abundance of its food supply. (See Figure IV-2) The dominant groups in the Bay which are important as forage are phytoplankton, zooplankton, benthic organisms, and small fish species (e.g., bay anchovy and menhaden). Although fish populations are more likely to be affected by the entrainment of their ichthyoplankton, they could also be affected by a change in the density of their food. These indirect effects may propagate through several trophic levels, although they are unlikely to be measurable beyond one link along the food chain.

Plant operations also affect particular species through modification of the physical/chemical environment. Biocide residuals may accumulate in areas around the plant, and temperatures are elevated by varying amounts in the discharge vicinity. Discharge jets may also scour the bottom sediments, creating locally uninhabitable zones for benthic organisms. If such habitat modifications make an area unsuitable for use by some species, a subsequent decline in their abundance can occur locally.

B. Aquatic Habitats

The central concept underlying the cumulative aquatic assessment presented here is that the Chesapeake Bay and its tributary estuarine waters are composed of distinct habitat types. These habitat types are defined by water salinity, which is the environmental variable most important in controlling distributions of organisms in estuaries. Each of these habitats can be identified with unique functions in producing or supporting important resource elements, although their biotic components overlap, and their extent varies seasonally. Cumulative impact will be assessed in terms of significant effects on the biota over the entire extent of each characteristic habitat type within Maryland, with the emphasis on whether the long-term integrity of each estuarine habitat and its characteristic functions are maintained. In order to accomplish this assessment the salinity zones must be defined and the distribution of the power plants among the zones determined.

The salinity zones designating the habitat types can be defined by the Venice system of classification (1) as:

Habitat	Salinity Ranges
Euhaline (Marine)	30.0 ppt - 35.0 parts per thousand (ppt)
Polyhaline	18.0 ppt - 30.0 ppt
Mesohaline	5.0 ppt - 18.0 ppt
Oligohaline	0.5 ppt - 5.0 ppt
Tidal fresh	0 ppt - 0.5 ppt
Riverine	0 ppt

The major ecological functions of each habitat are:

- Polyhaline and Marine

  These high salinity waters are primary sites of the blue crab spawning and development; they also support hard clams. Several fish species, (e.g., spot, croaker, and Atlantic menhaden) whose young and adults seasonally feed in upper estuarine zones, spawn and develop in these regions. These zones generally do not exist in the Maryland portion of the Chesapeake Bay.

- Mesohaline

These medium salinity regions are the primary areas of production for those shellfish (clams, oysters) whose early life stages are planktonic. Mesohaline waters also support the adult crab populations and produce most of the estuarine forage fish biomass. Therefore these waters serve as feeding areas for large predator fish (e.g., bluefish, striped bass).

- Oligohaline

These brackish water environments support resident estuarine fish populations and serve as their spawning and nursery grounds. Although these fish populations serve primarily as forage organisms for larger fish, they may also be exploited by man. The areas also are feeding grounds for migratory marine and estuarine species such as menhaden and white perch. Some spawning of anadromous fish also occurs here.

- Tidal Fresh

These segments of estuaries are within tidal influence but without a significant salt intrusion. They provide spawning and nursery areas for anadromous fish species and also support their larvae and juveniles during the spring and summer months. In addition, resident fish species, some adapted to both this and riverine environments, spend their entire life cycles in this zone. The striped bass is a particularly important example of a species using this environment as a spawning and nursery area.

- Riverine

These freshwater habitats beyond the head of the estuary have resident fish populations and supporting bottom (benthic) communities adapted to constant freshwater conditions.

The locations of these zones change seasonally as a result of changes in the amount of freshwater inflow (2). Table IV-2 indicates the zones in which Maryland power plants are located and designates their zone according to season. The majority of plants in Maryland are situated in oligohaline-mesohaline regions. Data collected since publication of the last Cumulative Environmental Impact Report (CEIR) (3) show that four plants previously considered to be in tidal fresh-oligohaline areas (Wagner, Westport, Gould Street, Riverside) are actually on oligohaline-mesohaline waters. The largest of the power plants in the state (Calvert Cliffs, Chalk Point, and Morgantown) are sited in mesohaline regions (at least in the fall) and new plants (e.g., Elms) will also be in the mesohaline habitat. There are no power plants in the polyhaline and marine habitats along the Atlantic shoreline in Maryland.

Table IV-2. Power Plant Location by Salinity Regime.

Power Plant	Net Capacity (MW)	Spring				Fall			
		Riverine	Tidal-fresh	Oligo-haline	Meso-Haline	Riverine	Tidal-fresh	Oligo-haline	Meso-haline
Brandon Shores	1,250			x					x
Calvert Cliffs	1,620				x				x
Chalk Point	1,265			x					x
Conowingo (hydro)	512	x							
C.P. Crane	384		x					x	
Dickerson	545	x				x			
Gould Street	103			x					x
Morgantown	1,163			x					x
Possum Point	478		x					x	
R.P. Smith	129	x				x			
Riverside	321			x					x
Vienna	241			x				x	
Wagner	988			x					x
Westport	177			x					x
Total Capacity by Zone		1,186	2,112	4,258	1,620	1,186	0	2,353	5,637

C. Regulatory Considerations

The intake, use, and discharge of waters for power plant use are regulated through the issuance of surface water appropriation permits and Natural Pollutant Discharge Elimination Systems (NPDES) discharge permits. These permits reflect Federal and State constraints on the amount of water used, the type of intake employed, and the chemical and physical characteristics of the effluent.

The evaluation of existing once-through cooling systems to determine if cooling towers are required to protect the "balanced, indigenous population" is done in conjunction with the NPDES permit process and the Code of Maryland Regulations (COMAR) 08.05.04.13. Under the State regulations, an initial evaluation of impact is made based on the size of the thermal plume with respect to mixing zone criteria and the importance of the area as a spawning and nursery area. If the plant fails to pass these screening criteria, a more detailed evaluation is required. Impingement (and intake technology used to minimize it) is also treated under the State regulation. Yearly impingement total are estimated (as discussed later in this chapter) and various methods of mitigation are evaluated to determine which techniques are cost-effective. The status of the various Maryland plants which fall under this regulation is listed in Appendix B.

The Dickerson Power Plant wastewater treatment system was under a compliance order during 1978-79. Testing of the new system was completed in August, 1979 with the plant passing a compliance test in February, 1980.

D. Aquatic Impact Assessment

Many additional monitoring studies have been completed since the publication of the last CEIR (3) including several carried out at sites where data had previously not been available. All additional data available through November 1980 has been incorporated into the following assessment of power plant impacts on each of the salinity zones in Maryland.

Mesohaline

This medium salinity zone accounts for the greatest percentage of aquatic habitat in the Maryland portion of the Chesapeake Bay. It serves as the primary area of shellfish and forage fish production and as nursery and feeding ground for most commerically and recreationally valuable fish species and blue crabs. Three of the plants located in this zone (Calvert Cliffs, Chalk Point, and Morgantown [summer-fall]) are the largest and newest in the State. All three of these plants have been or are being intensively studied. The findings of the Calvert Cliffs monitoring studies covering the preplant period as well as the first five years of operation (1975-1980) have been reported in References 4 through 14. The results of these studies are summarized in Reference 15. The Morgantown monitoring findings are summarized in References 16 and 17. The results of the Chalk Point Studies in the 1960's are summarized in Reference 18. This plant is currently being intensively studied.

Four additional plants (Gould Street, Riverside, H. A. Wagner, and Westport) are located on the Patapsco River and its tributaries in the Baltimore area. Salinities at these plants tend to be in the oligohaline range in the spring and low mesohaline during the remainder of the year. In the past, environmental degradation which was not related to these plants had elminated the area as an important anadromous spawning ground (19). However, as will be discussed below, numerous species of aquatic biota are currently using the area. Except for Wagner, these plants are all older than 20 years, are used for peaking and cycling service, and have seen decreased service since Calvert Cliffs came on-line. Because of the close proximity of these four plants, they will be discussed as a group in the material presented below.

- Entrainment

In-plant losses of about 30-70 percent of entrained zooplankton have been observed at Calvert Cliffs, but the percentage loss was very variable and often species-specific. Losses of entrained phytoplankton biomass and productivity (on the order of 30% for each) have also been observed, primarily in late summer and fall. No significant nearfield depletion of zoo- or phytoplankton has been observed. Regional reduction in zooplankton density and phytoplankton assimilation was noted in 1975, but the widespread nature of the changes suggests the plant was not the causative agent. Similar reductions were not observedin the nearfield in later years. A review of these studies is contained in Reference 15.

High zooplankton mortalities (50 %) have been measured as a result of entrainment at Morgantown only under the most severe thermal and chlorine stress conditions. Phytoplankton productivity was also reduced during those periods (16) . However, no changes in zooplankton and phytoplankton populations in the river were detected (16). It was estimated that 2 percent of the plankton transported past the plant would be destroyed by entrainment (16, 17). No adverse impact would result from losses of this magnitude to the rapidly reproducing plankton populations.

Large mortality of entrained organisms was reported at Chalk Point in studies done in the 1960's, with both thermal and biocide stresses appearing to be important causes (20). Near-field depletions of jellyfish were also noted, but no changes in river populations of copepods were found (18). More recent phytoplankton studies (21) also suggest a reduction in photosynthetic activity and chlorophyll concentrations between intake and discharge that is more marked during periods of chlorination. Similarly, recent zooplankton studies indicate entrainment losses of 21 and 52 percent without and with chlorination, respectively, during summer, but no apparent losses during winter sampling (22) (no chlorination is used in winter). Some plant effects on near-field phytoplankton biomass and productivity have also been observed in recent studies (24), with enhancement occurring in winter and depresssion in summer. However, these effects were inconsistent (21, 25). A lower density of zooplankton in the plant vicinity was observed during one study (22), but not during others (22, 26).

No zooplankton or phytoplankton entrainment studies have been done at Baltimore harbor plants. For phyto- and zooplankton entrainment we conclude that the findings at Morgantown and Calvert Cliffs are similar. Entrainment losses of phytoplankton and zooplankton do occur, but high reproduction rates of the affected populations compensate for the plant effects. Based on these findings, cumulative effects would not be expected.

At Chalk Point, the receiving water body has relatively low flushing rates, and near-field effects are detected. However, the effects are not consistently present. Further evaluations are currently underway to assess impacts at the plant. The assessment is complicated by the existence of other stresses on this ecosystem, such as sewage treatment plant discharge and non-point source pollution.

Eggs and larvae of bay anchovy, naked goby, and hogchoker (all forage species) are found in the Calvert Cliffs vicinity and are entrained. Densities near the plant have not differed significantly from those observed beyond the area of plant influence, and, in some cases, densities near the plant were highest (15). No conclusive evidence of ichthyoplankton depletion in the plant vicinity exists (15).

The same species of larvae are found at Morgantown, as at Calvert Cliffs. Nearfield ichthyoplankton depletions were not detectable at Morgantown (16).

Data from recent ichthyoplankton studies at Chalk Point (27, 28) have not yet been analysed to determine if depletions occur in the vicinity of the plant. Anchovy, naked goby, silversides, and hogchoker are the dominant ichthyoplankton species in the plant area. The data thus far suggest that striped bass and white perch larvae in the Patuxent are concentrated upstream and away from the plant, but that some larvae could be entrained under certain conditions of river flow (29).

Ichthyoplankton entrainment studies carried out at the Baltimore harbor plants in 1979 and 1980 indicate that entrainment rates at Gould Street are low, while those at Riverside and Wagner are higher and similar to each other (30, 31, 32). Major species spawning in the Harbor include bay anchovy, Atlantic silverside, tidewater silverside, naked goby, rough silverside, and hogchoker (30, 31, 33, 34). Entrainment at Gould street is dominated by naked goby (77%), juvenile eels (5%), and bay anchovy larvae (5%) (31). At Riverside,bay anchovy larvae dominated (43%), together with naked goby (24%), and tidewater silversides (11%) (32). Species entrained at Wagner included gobies (30%) bay anchovy (29%) and menhaden (19%) (30). These results confirm that the Baltimore area plants are not located in spawning areas of important exploited fish species.

In general it is found that the entrained ichthyoplankton at all the mesohaline plants belong to small forage species, mainly bay anchovy, silversides, naked goby, and hogchoker. These species spawn throughout the Maryland portion of the Chesapeake Bay and are ubiquitously distributed there. Thus localized losses at the plants under discussion are insufficient to cause decrease in Bay-wide stocks. When the negligible near-field effects observed to data are also considered, no cumulative Bay-wide impacts of ichthyoplankton entrainment at all the power plants are likely.

Chalk Point has an additional entrainment effect due to the lack of screens in front of the augmentation pumps used during the summer months. Without these screens, fish and crabs that would normally be impinged may be entrained into the pumps. Studies to quantify the magnitude of these losses have been complicated by difficulties in deploying sampling gear near the pumps. The studies have suggested that fish and crabs do pass through the pumps, however, an estimate of the number entrained could not be made (35).

- Impingement

Fish and crab impingement data from Calvert Cliffs, Morgantown, and Chalk Point, collected during the period 1976 through 1979, are presented in Table IV-3 along with data taken from the last CEIR (3) covering the period 1975 to 1977. Although the values presented represent an estimated total annual impingement, the years are not the same for each plant. However, they do permit an assessment of the consistency of impingement over a period of about 5 years. In some respects, data from the two time periods are very similar: the same six species account for 93 and 78 percent of the total fish impinged in the two time periods, respectively; the number of blue crabs impinged is nearly the same for the two time periods. The data differ in two respects: the total number of fish impinged decreased substantially from the earlier to the more recent time period, and numbers of impinged individuals of several species included in the "other" category (e.g., winter flounder, gizzard shad, and blueback herring) increased substantially.

Impingement data from Baltimore harbor plants are presented in Table IV-4. The same two species dominate impingement here: menhaden and spot. However, other species differences are evident; no substantial numbers of hogchoker are taken at Baltimore plants, while gizzard shad do not appear insignificant numbers at the other three plants. These differences may reflect the fact that the Baltimore plants are located on mesohaline waters of lower salinity than at the other three plants.

Table IV-5 presents the results of impingement mortality studies done at Calvert Cliffs in 1979 (14). These data suggest that nearly all crabs and hogchokers, and substantial percentages of other major species, are not directly killed by impingement. Similar mortality data are not available for other meoshaline plants, where screens are operated differently from those at Calvert Cliffs. However, the Calvert Cliffs data do suggest that impingement totals at all mesohaline plants do not necessarily represent numbers of fish lost to the ecosystem.

The implications of impingement losses to the Chesapeake Bay ecosystem and its fisheries were discussed in detail in the last CEIR (3). Because the nature of impingement at these mesohaline power plants has remained similar to that reported and discussed in the last CEIR, the significance of impingement as presented there remains the same: the

Table IV-3. Estimated Annual Total Impingement by Species at Three Power Plants in Mesohaline Waters (Calvert Cliffs, Chalk Point, Morgantown).

Species	1976[a] Number	1976[a] Percent of Total	1976 - 1979[b] Number	1976 - 1979[b] Percent of Total
Atlantic Menhaden[c]	1,766,671	39	896,557	32
Spot[c]	1,821,367	40	424,632	15
Hogchoker	275,427	6	350,518	13
Bay Anchovy	135,543	3	316,629	11
Atlantic Croaker[c]	111,901	3	44,252	2
White Perch	106,110	2	140,705	5
Others	318,632	7	608,743	22
TOTAL FISH	4,535,651	100	2,782,036	100
Crabs	1,820,977		2,036,427	

(a) Data reproduced from the 1978 CEIR and are primarily from 1976.

(b) Excludes data used under (a); Calvert Cliffs data from 1979, all months (14); Chalk Point data from 1978, no data from January, February, and October (23,35); Morgantown data from May 1976 to May 1977 (17).

(c) Predominantly juveniles.

Table IV-4. Estimated Annual Impingement at Baltimore-Area Power Plants (1978-1979); Number of Individuals.

Species	Gould St.[a]	Riverside[b]	Wagner[c]	Total	Percent
Spot	745	176	554,151	555,072	54
Atlantic Menhaden	2,982	34,267	244,666	281,915	27
Atlantic Croaker	9,402	21,055	49,439	79,896	8
Gizzard Shad	3,786	6,758	20,966	31,510	3
Atlantic Silverside	223	414	21,230	21,867	2
White Perch	287	516	12,723	13,526	1
Other	686	2,516	40,752	43,954	5
					100
Blue Crab	6,348	9,241	430,045		

(a) Data from Ref. 31

(b) Data from Ref. 32

(c) Data from Ref. 30

species comprising most of the impingement total are ubiquitous and abundant in the mesohaline zone; juveniles of all species dominate in the impingement totals; and no changes in fish density or community composition in the vicinity of these plants have been observed. Thus, impingement losses appear to be too small to alter significantly the size of Bay populations of affected species.

Table IV-5
Percent Survival and Percent Loss of Equilibrium (LOE) of Major Fish Species Impinged at Calvert Cliffs in 1979

Species	Percent Survival	Percent LOE
Atlantic Menhaden	49.27	1.41
Spot	87.34	0.14
Hogchoker	>99.00	0.0
Bay Anchovy	66.82	2.66
Atlantic Croaker	3.81	1.04
White Perch	73.08	11.54
Blue Crab	>99.00	0.0

Data from Reference 14.

- Discharge Effects and Habitat Modification

The maximum radial extent of the 2°C excess temperature isotherm at Calvert Cliffs, with Units 1 and 2 both operating, was 2.3 km, and the areas enclosed by the isotherm did not exceed 50×10^4 m^2 on 14 of the 17 occasions when surveys were made[1] (20). Some depletion of zooplankton was noted near the plant, but it appeared to be attributable to in-plant entrainment rather than to thermal plume effects (15). No near-field effects on phytoplankton were observed during 2-unit operation (15). Although discharge effects on benthos as a result of bottom scouring have continued to be observed, in many instances the induced changes have resulted in increases in population biomass (15). Some benthic species near the plant have increased in abundance, possibly due to organic enrichment of the sediments caused by mortality of entrained plankton. Occasionally, higher copper content was observed in oysters in the immediate vicinity of the discharge during 2-unit operations, but densities of oysters here are relatively low and the area is not regularly fished (15). No plant effects on the feeding behavior of fish in the discharge area have been observed. No plant effects on distribution, abundance, or condition of fish in the discharge vicinity have been discerned (15).

At Morgantown the thermal plume as defined by the 2°C isotherm was generally about 0.1×10^4 to 0.6×10^4 m^2 in size, and occasionally was as great as 32×10^4 m^2. Morgantown findings are consistent with

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1 1×10^4 m^2 = 2.5 acres.

Calvert Cliffs results. No significant influence of the thermal discharge has been found (17).

Of the three largest mesohaline power plants, Chalk Point has the greatest potential for causing discharge effects, because the Patuxent estuary on which it is sited is shallow and has relatively low flows. The 24-hour average radial extent of the 2°C excess temperature isotherm was 1.98 km, but lower excess temperatures could be detected over a broad portion of the estuary (36, 37, 38, 39). The area of bottom covered by the 1°C excess temperature isotherm extends as far as 6 km upstream and downstream of the plant (40). Studies conducted in the 1960's revealed some plant discharge effects. Both erosion of copper from condenser tubes and uptake by oysters of copper discharged from the plant was found. The conditions that caused the release of copper were later corrected by changing the condenser material (41). Large concentrations of fish have appeared in fall and winter in the discharge canal and now supports an intensive sport fishery there. Large kills of fish and crabs in the discharge canal, attributed to accidental excessive discharge of chlorine were reported in the 1960's (18, 42). Similar kills have not been reported in recent years.

The recent studies on phytoplankton and zooplankton (already discussed in the Entrainment section), revealed some inconsistently ocurring near-field plant effects on these trophic groups. The effects are probably attributable more to entrainment losses than to habitat modifications caused by plant discharges.

In a 1979 study (40), the geographic distribution of species of benthic organisms showed no deleterious plant effects. Rather, densities of organisms in the plant vicinity often were 4 to 10 times higher than at upstream and downstream reference stations, possibly due to organic enrichment resulting from settling of planktonic organisms killed by entrainment. Fish studies have shown that distributions and feeding behavior of some species are influenced by plant operations (43). The significance of these non-lethal effects on fish stocks has not yet been determined, but they are likely to be inconsequential.

Baltimore harbor plants are situated on relatively small water bodies and exert substantial effects on the thermal regimes of these water bodies. The maximum radial extent of the 2°C isotherm averages 0.2 km at Gould Street (31), 0.3 km at Riverside (32) and 2.1 km at Wagner (30). Average areas enclosed are 26 x 10^4 m^2 and 110 x 10^4 m^2 for Riverside and Wagner, respectively (30, 31). Plumes at all three plants are strongly influenced by wind, and wind events often determine the length of time during which elevated temperatures will exist in a given location. Five to ten percent of the surface of Baltimore harbor appears to be affected by the thermal plumes of these three plants.

Near-field studies at Baltimore harbor plants are currently being conducted under funding from PPSP and BG&E. No data from those studies are yet available.

When the results of studies at all mesohaline plants are considered, a picture emerges that indicates a low probability of cumulative impact on the mesohaline environment. Although plankton entrainment losses have been measured from time to time at several of the power plants, there is no consistent occurence of measurable plankton depletion in the waters around the plant. This lack of consistent effects is probably due to the high reproduction rate of the plankton, and suggests that there is no cumulative influence due to plankton entrainment. Since no important commercial or recreational species spawn in this habitat, entrainment losses of ichthyoplankton have little economic significance. Localized effects on benthic organisms, including shellfish, are sometimes evident. These effects have no significance beyond the immediate discharge areas. A comparison of recent studies with the studies described in the previous CEIR published 2 years ago show no first-time or increased effects on any trophic level.

Current studies at Chalk Point and the Baltimore harbor plants will permit a more definitive assessment of impact at those sites.

Tidal Fresh - Oligohaline

These habitat zones have significant value as the major spawning area of anadromous fish, which as a group have accounted, on the average, for about 65% of the total monetary value of commercially harvested finfish from 1972 to 1976 in Maryland. Since anadromous spawning occurs in the spring, the plants of most concern are those in the tidal fresh-oligohaline zone at that time, particularly those sited near striped bass spawning areas. However, the zone also serves as a nursery area for many important fish species year around.

Seven plants use oligohaline waters for cooling purposes in the spring (Table IV-2). At six of these seven plants, salinity is in the mesohaline range during most of the remainder of the year. Impacts associated with those plants (Chalk Point, Morgantown and the Baltimore area plants) was discussed in the preceeding mesohaline section. Of these plants only Morgantown is situated near waters of sufficiently low salinity to be of interest as far as striped bass impact is concerned.

The remaining plants to be discussed here are Possum Point, Vienna and Crane. Possum Point, on the Potomac, and Vienna, on the Nanticoke, are both in the vicinity of major striped bass spawning areas. Crane, though located on tidal fresh-oligohaline waters, does not impact on a striped bass spawning area.

- Entrainment

  A detailed, in-plant phytoplankton entrainment study at Crane is currently being conducted under BG&E funding. Samples taken at intake and discharge locations during nearfield studies (33, 44, 45, 46) showed no discernable loss of either zooplankton or phytoplankton, and suggest an enhancement of phytoplankton productivity. Entrained zooplankton from Seneca Creek may be enhancing zooplankton populations in the discharge area (47). Entrainment of zooplankton and phytoplankton of the Vienna plant will be 0.20 - 0.25 percent of the organisms moving past the plants when Unit 9 comes on line (see below) (53). Such losses will have negligible effects.

Results of studies conducted in 1979 indicate that relatively low numbers of ichthyoplankton species and individuals are entrained at the Crane Station. Entrainment was highest in summer, when bay anchovy and naked goby were the dominant species. Other commonly entrained species were white perch and tidewater silversides (48). Highest densities entrained were 6 larvae/100m^3 of cooling water.

Possum Point is sited on the striped bass spawning grounds in the Potomac estuary. Recent work indicates that the plant entrains a maximum of about 2 percent of the striped bass larvae produced annually in the Potomac. Morgantown is located 20 km downstream of the center of the striped bass spawning area in the Potomac. Few eggs or larvae (less than 0.01% of Potomac production) are entrained (49, 50, 51). Consequently, the operation of this plant has no significant impact on the striped bass population. Vienna is in the midst of the spawning area in the Nanticoke. With the retirement of units 5, 6 and 7 (68 MW total) using once-through cooling (withdrawal 3.6 m^3/sec) only unit 8 (162 MW) using a cooling tower (withdrawal 0.12 m^3/sec from the discharge of units 5, 6, and 7) remains. Delmarva Power and Light has proposed a 500-MW expansion (Unit 9, 1988 completion date) which will withdraw 0.42 m^3/sec for cooling and plant purposes. The proposed intake of this unit includes a fine mesh, wedge wire screen which is designed to minimize entrainment of fish eggs and larvae (52). The estimated amounts oof striped bass eggs and larvae entrained by the previously existing units have been about 8 percent (of the Nanticoke Stock) annually from 1977 to 1979. When Unit 9 begins operation ichthyoplankton entrainment is predicted to average 2 percent (52).

The potential impact of entrainment by a power plant on the overall striped bass stock can be estimated by examining the contribution of the impacted area to total spawning in the Maryland part of the Chesapeake Bay and its tributaries. This contribution can be estimated from the commercial catch records for the months (March and April) just prior to spawning. This catch is assumed to be proportional to the presence of spawning adults and hence to the spawn. These data are summarized in Table IV-6 which shows, for example, the Potomac River spawning constitutes about one fourth of the total striped bass spawning in Maryland. Therefore, under our assumption, a 1 percent loss of striped bass larave in the Potomac would translate to a 0.25 percent loss of the Maryland fisheries, and the 2 percent loss at Possum Point translates into a 0.5 percent loss to the Maryland fisheries. The consequences of the 2 percent loss of ichthyoplankton at Vienna is compounded over generations (because of local effects) and could increase the estimated local loss of adults to 4 percent (52) since Table IV-6 shows that the Nanticoke-Wicomico region accounts for 12 percent of the commercial catch on the average this loss of adults is equivalent to a loss of almost 0.5 percent of the Maryland Bay Stock. The total potential loss to the Maryland striped bass population from the operation of these power plants will thus be 1 percent. The reported commercial catch in Maryland averaged 4.6 million lbs. annually from 1960 to 1975 (52), and the average annual sports catch is estimated to roughly equal the commercial catch (54). Consequently the 1 percent loss of striped bass ichtyoplankton through entrainment is equivalent to an annual loss of about 92,000 lbs. of striped bass based on the 1960 to 1975 average. In recent years the Maryland striped bass catch has declined substantially compared to the 1960-1975 average. Therefore, the calculated loss of striped bass in pounds will be correspondingly less.

For the tidal fresh-oligohaline plants the conclusion is that cumulative impacts due to zooplankton and phytoplankton entrainment at oligohaline plants have not been detected. Impact is unlikely because of the high reproduction rates of these groups of organisms. Cumulative impact of all plants in Maryland on striped bass due to entrainment of eggs and larvae would be about 1.0 percent of annual landings.

- Impingement

Impingement at Chalk Point, Morgantown, and the Baltimore area plants, where waters are oligohaline for only a few months in the spring, was discussed in the previous section on mesohaline plants. Impingement of juvenile and adult fish at Vienna is negligible (53).

Impingement data from Crane have only recently become available. The Crane data from 1978-1979 presented in Table IV-7 can be contrasted to that for mesohaline plants present in Tables IV-3 and 4. Atlantic menhaden and spot are dominant at both sets of mesohaline plants, while white perch replace spot as a dominant species at Crane. It is interesting to note that the majority of white perch recorded as impinged at mesohaline plants (Table IV-3) was taken at Morgantown in the spring, when waters at that site were actually oligohaline (16). Thus, white perch are demonstrated to be primarily an oligohaline species. Other species differences are evident between impingement at the two groups of mesohaline plants: gizzard shad and silversides are major components of impingement at the Baltimore plants whereas they are not prominent at the other mesohaline plants. This result may reflect the fact that the Baltimore plants are located on lower salinity mesohaline water. The data discussed here suggest that consequences of impingement at oligohaline plants are similar to those of impingement at mesohaline plants: the major species impinged are ubiquitous and abundant throughout Maryland tidal waters; impingement losses appear too small to have a detectable effect on stock sizes of affected species. For example, white perch are impinged in substantial numbers and have important commercial and recreational value. This species is, however, abundant throughout Maryland (2), and annual impingement losses are very small relative to the total commercial and recreational harvest. Thus, stocks are not likely to be affected.

Table IV-6. Commercial Catch of Striped Bass in March and April by Region in the Maryland Portion of the Chesapeake Bay, by Percent.

Year	Upper Bay above Sassafras River	Bay Bridge to Sassafras River	Chester River	Cove Point to Bay Bridge	Choptank River	Virginia to Cove Point	Patuxent River	Nanticoke River Wicomico River	Potomac River (including Virginia side)
1972	8.67	30.76	4.61	5.76	10.02	2.37	2.22	15.87	19.67
1971	10.13	27.24	2.39	5.66	10.58	0.85	4.07	13.15	25.87
1970	9.37	34.86	5.18	4.90	10.84	0.99	2.65	8.81	22.14
1969	17.17	33.66	1.63	4.18	9.24	0.86	3.27	8.27	21.67
1968	12.04	24.20	1.76	3.69	6.40	1.25	2.09	11.61	36.74
1967	9.54	29.58	1.36	3.31	7.00	0.82	2.18	11.45	34.75
1966	6.03	22.91	2.73	2.84	10.37	1.65	1.07	19.34	33.03
Averages	10.73	29.50	2.80	4.30	9.10	1.25	2.49	12.28	27.46

From Ref. 3

Table IV-7
Estimated Annual Impingement at Crane Located in Tidal-Fresh Oligohaline Waters (1978-1979)

Species	Number	Percent
Atlantic Menhaden	246,353	50
White Perch	148,941	30
Spot	19,118	4
Gizzard Shad	14,255	3
Atlantic Silverside	1,022	<1
Atlantic Croaker	78	<1
Other	67,124	13

Data from Reference 48.

- Discharge Effects and Habitat Modification

Thermal plumes at Vienna were sufficiently small that discharge effects can be considered negligible (55). Studies at Crane in 1979 and 1980 have documented the extent of influence of the plant's thermal discharge (56). The 24-hr. averge radial extent of the 2°C excess temperature isotherm at that plant is 1.8 km, and an average area of 90 x 10^4 m^2 of river bottom is enclosed by that isotherm. Because of the relatively small dimension of the water body into which the discharge enters, (Saltpeter and Dundee Creeks), much of the creek system is thermally influenced. Thus, potential for thermal discharge effects is higher than in the case of the mesohaline plants.

At Crane, studies demonstrated that under extreme summer temperature conditions, the temperature in the immediate discharge area exceeded lethal limits for some zooplankton and inhibited photosynthesis by phytoplankton (44). Decreases in phytoplankton productivity and alternations in zooplankton community structure in late summer were observed in the discharge area (44, 46). However, during other periods phytoplankton productivity in the thermally affected area was enhanced and no effects on zooplankton abundances were evident (33, 45, 46). No major deleterious effects on submerged aquatic vegetation in the discharge area were noted (57, 58, 59). Vegatation growth appeared to be enhanced during some periods.

Benthic studies suggest that the brackish-water clam may be protected during cold winter periods by the thermal discharge, resulting in population enhancement (60, 61, 62). A summertime decrease of about 30 percent in density of an amphipod Leptocheirus in the discharge area was observed in 1979 (44). Several species in the discharge area also showed greater population build-ups in Spring 1980, suggesting accelerated growth or development (62).

Finfish studies in summer showed that white perch and, to some extent, spot were attracted to the plume (63).In Spring white perch avoided the plume region, whereas pumpkinseed were attracted to it. In a follow-up extended summer study (64) white perch did not show preference for the discharge region. The same study also found that low numbers of spot occurred in shallow creeks as well as in the discharge area, suggesting a generalized creek effect.

One effect which might be construed as cumulative, though not necessarily as deleterious, is a change in the zooplankton and benthic communities in the Crane discharge area. As the plant takes higher salinity water from the intake area and discharges it into lower salinity receiving waters, it also transports an oligohaline fauna into a location which, without the plant, would probably harbor a freshwater fauna (47, 62). This higher salinity water also provides a habitat more suited to oligohaline benthic and planktonic species during certain times of the year.

Riverine

The only Maryland steam electric stations located on riverine waters are R.P. Smith and Dickerson, both on the Potomac River. Each uses, at times, a substantial portion of average river flow for cooling purposes. The plants are relatively old, of low to medium generating capacity, and located in areas inhabited by typical warm water "riverine" biological communities (65). Conowingo Dam on the Susquehanna River is the only large hydroelectric generating station in Maryland. Significant stocks of fish, both comerically and recreationally important, inhabit the Susquehanna River below the dam.

- Entrainment

Limited entrainment data at the R.P. Smith plant are available from studies conducted in 1978 (66). Organisms primarily entrained were sucker and carp larvae, midges, and gammarid amphipods. Numbers entrained during the 3-month study period were very low, but the studies were not done during periods when high ichthyoplankton abundances were expected.

Entrainment at Dickerson during a 12-month study was an estimated 48 million fish eggs and larvae and one million juveniles which represents approximately 10 percent of the organisms drifting past the plant (67). Species entrained were primarily carp, spottail shiner, and spotfin shiner. Since most of these entrained species are nest builders or have demersal eggs, drifting eggs susceptible to entrainment represent only a small percentage of the total spawn. Maximum local population loss of 4.1 and 2.3 percent are predicted for spottail shiner and redbreast sunfish, respectively (68). Thus, localized entrainment effects will not alter river populations of these forage and rough species.

Very few eggs and larvae of sport fish were entrained at either plant; thus, direct entrainment effects on sport fish populations would be negligible. The species entrained are ubiquitous in the Potomac and spawn over the entire freshwater reach of the river in Maryland.

* Impingement

Very few fish (a total of about 300) were impinged at R. P. Smith during studies in 1978 (66). Golden redhorse and shiners dominated, and 72 percent of the annual total was taken in June. Impingement at this level is negligible in terms of effects on fish populations.

Other 1978 studies showed an estimated annual total of about 256,000 fish impinged at Dickerson (67). Primary species were spottail shiner, channel catfish, sunfish (several species), spotfin shiner, and smallmouth bass. Impingement was highest in winter and spring. The shiners are important forage species; the rest are important sportfish. With no data available from periods prior to plant operation, an assessment of whether the plant has had a deleterious impact on these fish stocks is difficult to make. Detection of effects on populations near the plant is made more difficult by the fact that fish are seasonally attracted and repelled by the plant's thermal plume (67).

* Discharge Effects and Habitat Modification

Data from thermal plume surveys at both Dickerson and R. P. Smith have become available since publication of the 1978 CEIR (3). At Dickerson, the 2°C excess temperature isotherm extended downstream more than 20 km and entended across the river approximately two thirds of its width during summer, low-flow conditions (67). The thermally influenced area is largest during summer and fall.

Discharge effects on insects were noted in the immediate plant vicinity in studies conducted in 1977. Decreases in abundance, numbers of species, and growth rates were found (67). Effects on fish were difficult to assess because of the seasonal change in response of many species to the thermal plume; avoidance during summer and fall, and attraction in winter and spring. Although literature data suggest that thermal conditions in summer are often deleterious for growth and reproduction of several species, no clear evidence of cumulative, adverse impact of river-wide stocks of any species is apparent in the data collected. Discharge effects apparently are localized (about 2.5 km in extent), and the area of greatest impact is not particularly critical for any of the fish species present.

The size of the thermal plume at R. P. Smith depends on river flow and meteorological conditions and is highly variable (66). The maximum downstream extent of the 2°C excess temperature isotherm is about 7 km and the same isotherm seldom extends further than 30 m across the river about one third of the width from the Maryland shore. Discharge effects on periphyton and benthic organisms (primarily insects) have been observed to be inconsistant and tend to be small (69, 70, 71). The riverine habitat is very heterogeneous in the vicinity of the plant, and communities at different unaffected stations often differ from each other. This situation complicates the evaluation of discharge effecs. However, the data do not suggest the existence of a well-defined area of depleted or modified biota in the discharge vicinity. This, in turn, suggests the absence of significant cumulative impact on periphyton and benthos. Fish distribution is influenced by the thermal plume. Golden redhorse, the dominant species in the area, is concentrated in the plume in winter. Summer avoidance was not evident for any species when plant discharge temperature was low (70). During one summer period with high plant discharge temperature resulting in near-field temperatures of 40°C, no live finfish were taken in the discharge plume. If localized distribution effects are discounted, fish data show no major differences between the fish community inhabiting the general region of the river near the plant and communities inhabiting unaffected areas upstream and across-stream. Those data suggest the absence of significant cumulative impact on fish.

Conowingo Dam - Hydroelectric Facility

The manner in which this hydroelectric facility can impact an aquatic ecosystem is entirely different from that in which nuclear or fossil fuel plants create effects. Although entrainment of organisms through the turbines of the facility may occur, the more important modes of effect relate to the facility's modification of flow regimes, water oxygen content, and habitat area.

The Conowingo Dam is operated as a peaking power generating unit, with fullest operation scheduled for weekday afternoons. Generation is reduced or stopped at night, and frequently also on weekends, to allow the reservoir level to rise. The generating station has seven 36-MW turbines and four 56-MW turbines. The addition of the four larger turbines in 1967 increased the maximum water use from 45,000 cfs to 85,000 cfs. By comparison, median monthly-average flows of the Susquehanna River range from 7,000 cfs (August) to 65,000 cfs (March).

Several water flow, water quality, and fisheries problems in the Susquehanna are thought to be related to Conowingo's operating patterns. Fluctuations in water levels below the dam caused by the mode of operation of the turbines periodically expose large aras of river bottom to the air. Benthic biomass may be reduced in these dewatered areas thus decreasing food availability for some resident fish species. Additionally, demersal fish eggs may become stranded and exposed to air as the water level falls after a flow reduction.

Water temperature, and, to some extent, dissolved oxygen (DO) concentrations in the river below the dam seem to reflect conditions near the bottom of Conowingo Pond. Although classical thermal stratification has never been observed in the pond, DO concentrations decrease with depth from saturation values at the surface to less than 2 ppm near the bottom (23 m below surface). Intake structures for the turbines draw water from 20 m below the surface, thus releasing this low DO water into the river.

Oxygen problems also have occurred in the river below the dam during periods when no water is being released. Biota in isolated pools consume available oxygen and can create low DO conditions. The danger of fish kills or other biological impacts are most severe in summer when river flow is near its annual minimum and prolonged shutdowns are required to refill the reservoir. At the same time, water temperature is high (approaching 30°C), resulting in a reduction in its DO capacity. These problems are exacerbated during periods when large numbers of fish are present below the dam, such as during anadromous spawning runs. The high fish densities accelerate the rate of oxygen depletion. Such events led to the repeated occurrence of resident and anadromous fish kills below Conowingo Dam in the 1960's.

These problems and the recent dramatic declines in upper Chesapeake Bay landings of American shad and other anadromous species (72), prompted the Maryland Department of Natural Resources to initiate studies through the Power Plant Siting Program to obtain data needed to assess these problems and develop solutions. The information will also be submitted during the Conowingo relicensing proceedings under the Federal Energy Regulatory Commission (FERC).

Some preliminary findings of these studies are:

- At high discharge volumes, the DO concentration of the river below the dam depends on that of the bottom layer of the reservoir (which is discharged through the dam turbines). At low flows, downstream DO distribution is patchy and is heavily influenced by local metabolic processes, including the unpredictable aggregations of fish which might cause localized anoxic conditions.

- In 1980, the population size of shad in the Upper Bay is below 10,000 adults, blueback herring is below 200,000 adults, and alewife and hickory shad populations are too small to estimate.

- Benthic invertebrate populations are extremely sparse on substrates which periodically dewater as a result of the present discharge pattern.

- In the Upper Bay, analyses of historical fisheries data have identified a weak relationship of shad landings to the general operating pattern of the dam (73).

Because of the absence of detailed historical biological data in the Susquehanna below Conowingo, a complete quantitative evaluation of the cumulative effects of Conowingo operations on the Susquehanna River ecosystem is not presently possible. Results of the on-going studies will provide data to further address this question.

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CHAPTER V

RADIOLOGICAL IMPACT

Nuclear power plants in the United States are licensed and regulated by the U.S. Nuclear Regulatory Commission. Conditions imposed in the operating licenses for each plant permit the routine discharge of low levels of radioactivity to the environment. These releases must be within the guidelines of the federal regulations contained in 10 CFR 50 Appendix I, and are restricted by limits on the radiation doses received offsite by a hypothetical maximum exposed individual (Table V-1). Annual total body doses cannot exceed 3 mrem per reactor for the aqueous pathway and 5 mrem per reactor for the atmospheric pathway. Aqueous pathway doses are received through ingestion of radioactivity in water and seafood, and exposure to contaminated water and sediments. Atmospheric pathway doses result from inhalation of gaseous and particulate radioactivity and ingestion of radionuclides deposited on, or assimilated by, terrestrial vegetation and animals.

The operator of each nuclear plant is required to conduct environmental monitoring to assure that dose criteria are met. In addition to these programs, state and federal agencies conduct monitoring activities to assure compliance. These radiological monitoring programs are designed to determine actual radionuclide concentrations in environmental media in order to provide estimates of the ultimate dose to man.

Environmental Studies and surveillance activities which define the impact of releases to the atmosphere are:

- Estimation of radionuclides discharged - Samples are collected from in-plant decay tanks and main vent filters to determine radionuclide concentrations in gases prior to release.

- Analysis of air samples - Air is sampled continuously and sample composites are analyzed weekly to detect radioiodine and radionuclides in air particulates.

- Analysis of precipitation - Precipitation is sampled continuously to detect radionuclides which wash out with airborne particulates.

- Analysis of soil and vegetation - These analyses indicate terrestrial radionuclide concentrations derived from deposition of atmospherically released radionuclides.

- Analysis of milk - This analysis indicates I-131 concentrations in dairy products as a result of animal ingestion of atmospheric iodine deposited on pasture grass.

- External radiation measurements - Thermoluminescence dosimeters (TLD) are used to provide an assessment of ambient dose levels and exposure rate variation.

Table V-1

10 CFR 50 Appendix I
Limiting conditions for operation of light-water-cooled nuclear power reactors to keep radioactivity in effluents to unrestricted areas as low as is reasonably achievable.

Type of Dose	Appendix I[a] Design Objectives	Point of Dose Evaluation
<u>Liquid Effluents</u>		
Dose to whole body from all pathways	3 mrem/yr per unit	Location of the highest dose offsite[b]
Dose to any organ	10 mrem/yr per unit	Same as above
<u>Gaseous Effluents</u>[c]		
Gamma dose in air	10 mrad/yr per unit	Location of the highest dose offsite[d]
Beta dose in air	20 mrad/yr per unit	Same as above
Dose to whole body of an individual	5 mrem/yr per unit	Location of the highest dose offsite[b]
Dose to skin of an individual	15 mrem/yr per unit	Same as above
<u>Radioiodines and Particulates[e] Released to the Atmosphere</u>		
Dose to any organ from all pathways	15 mrem/yr per unit	Location of the highest dose offsite[f]

(a) Evaluated for a maximum exposed individual.
(b) Evaluated at a location that is anticipated to be occupied during plant lifetime, or with respect to such potential land and water usage and food pathways as could actually exist during the term of plant operation.
(c) Calculated only for noble gases.
(d) Evaluated at a location that could be occupied during the term of plant operations.
(e) Doses due to carbon-14 and tritium intake from terrestrial food chains are included in this category.
(f) Evaluated at a location where an exposure pathway and dose receptor actually exist at the time of licensing. However, if the applicant determines design objectives with respect to radioactive iodine on the basis of existing conditions and if potential changes in land and water usage and food pathways could result in exposures in excess of the guideline values given above, the applicant should provide resonable assurance that a monitoring and surveillance program will be performed to determine: (1) the quantities of radioactive iodine actually released to the atmosphere and deposited relative to those estimated in the determination of design objectives; (2) whether changes in land and water usage and food pathways which would result in individual exposures greater than originally estimated have occurred; and (3) the content of radioactive iodine in foods involved in the changes, if they occur.

Those studies which define the impact of liquid effluent releases are:

- Estimation of radionuclides discharged - Samples from in-plant monitor tanks and steam generator blowdown are analyzed to determine radionuclide concentrations in liquid inventory prior to release.

- Analysis of Bay water - Samples of Chesapeake Bay water are analyzed to determine actual radionuclide concentrations.

- Analysis of Bay fishery - Samples of various species of finfish and shellfish are collected and analyzed to measure radionuclide concentations and predict dose to consumers.

- Analysis of other environmental biota - Samples of submerged aquatic vegetation and lower trophic-level fauna are analyzed to determine radionuclide concentrations within the food chain.

- Analysis of sediments - Samples are analyzed to determine temporal and spatial distributions of sediment radionuclide concentrations.

The Maryland Power Plant Siting Program (PPSP) is responsible for assessing the radiological impact of nuclear power plants affecting Maryland. Those currently considered are Calvert Cliffs on the Chesapeake Bay in Maryland, and Peach Bottom and Three Mile Island on the Susquehanna River in Pennsylvania. Determining power plant radiological impact is complicated by the fact that the plant increment must be discerned from environmental concentrations of natural and weapons-test fallout radioactivity which already exist, or, in the case of weapons-test fallout, may be introduced during the monitoring period. Attributing a radiological effect to a specific plant may also be difficult under conditions where impacts may overlap. Such an instance occurred as a result of the Three Mile Island accident.

This chapter presents the PPSP's evaluation of the environmental impact on Maryland of radioactivity released by Calvert Cliffs, Peach Bottom and Three Mile Island during 1978-1980. This assessment is based on monitoring programs conducted by the individual utilities, the Maryland Department of Health and Mental Hygiene (DHMH), and the PPSP. Described herein are the monitoring programs conducted by the various agencies, the effluents released by each plant, and the actual distribution of radioactivity in the environment. Doses to man via the atmospheric and aqueous pathways are calculated. Comparisons with natural background doses, predictions made in Final Environmental Impact Statements, and operating license requirements are made where appropriate. A brief discussion of the quantity of electricity produced, and the wastes generated by each plant is also included.

A. Calvert Cliffs Nuclear Power Plant

The Calvert Cliffs Nuclear Power Plant (CCNPP), owned and operated by the Baltimore Gas and Electric Company (BG&E), is the only nuclear power plant located in Maryland. Each of its two units is a pressurized water reactor. Present ratings are 890 MWe gross each for Units 1 and 2 in winter, and 860 MWe gross in summer, when discharge water temperature restrictions may limit maximum load.

Unit 1 of the CCNPP, placed in commercial service on May 8, 1975, had as of the end of 1980 produced 29,594,233 MWh gross of electrical energy. Unit 2, placed in commercial service April 1, 1977, had as of the end of 1980, produced 22,728,967 MWh gross. Since the inception of commercial operation, Units 1 and 2 had as of the end of 1980, achieved cumulative unit capacity factors of 67.3% and 77.9%, respectively.

Releases to the Environment

Radionuclides discharged to the atmosphere and Chesapeake Bay by the Calvert Cliffs Nuclear Power Plant during 1978-1980 as reported by BG&E are given in Tables V-2 and V-3. Noble gases, which are not of significant environmental concern, comprise virtually 100% of the atmospheric releases. Other than Sr-89, no radionuclides released to the atmosphere were detectable in the environment during this period. Of the aquatic releases, Co-58, Co-60, Zn-65, and Ag-110m are the only bioaccumulable radionuclides routinely detected in the Bay environment. Cr-51 and Fe-59, both with relatively short half-lives (28 days and and 45 days respectively), were detected on two occasions.

Environmental Monitoring Programs

The Baltimore Gas and Electric Company (BG&E), the Maryland Department of Health and Mental Hygiene (DHMH), and the Maryland Power Plant Siting Program (PPSP) each conduct routine radiological monitoring programs designed to define the environmental impact of the releases described above. The BG&E program satisfies the environmental surveillance requirements imposed in its NRC operating license. The DHMH performs assurance monitoring to provide an independent confirmation of the utility program. The Power Plant Siting Program conducts a monitoring program and performs detailed investigations to describe the actual level of impact within ecosystem components. PPSP studies define the locational and trophic-level distribution of power plant radionuclides in the Calvert Cliffs area of the Chesapeake Bay. The programs conducted by the three agencies, described by sample type, collection frequency, and type of analysis, are presented in Tables V-4, V-5, V-6a, and V-6b.

Atmospheric and Terrestrial Radionuclide Distributions

Releases of radioactivity to the atmosphere during 1978-1980 did not contribute measurably to offsite radiation exposure as determined by TLD (7-11). Man-made radionuclides were, however, detected in the atmospheric and terrestrial environment on a few occasions during the period.

Iodine-131 was detected in the atmosphere at low levels during the week of March 20, 1978 by the utility and the State, both in the vicinity of the plant and at farfield locations. Because of its short half life, the presence of I-131 in the environment is indicative of a recent event, although not necessarily a power plant discharge, since it is also produced in the detonation of thermonuclear devices. In this case, its presence was attributed to the atmospheric weapons test conducted on March 10, 1978 by the Peoples Republic of China. Other gamma-emitting radionuclides associated

Table V-2

Total Gaseous Effluents (in Curies) Released by the Calvert Cliffs Nuclear Power Plant as Reported by BG&E (1-6)

Radionuclide	1978	1979	1980
Tritium	1.63	5.13	27.9
Noble Gases	26800.	10200.	2960.
Halogens	0.200	0.419	0.107
Other	0.064	1.75	0.045
Total Curies	26801.894	10207.299	2988.052
Na-24		0.00000239	
Ar-41	0.914	0.127	0.374
Cr-51	0.00000155	0.00000512	
Mn-54	0.00000395	0.0000232	0.00000183
Mn-56	0.00000906	0.00000327	0.0000205
Co-58	0.00605	0.00247	0.0185
Co-60	0.000318	0.000631	
Br-82	0.0000730	0.000108	0.0000470
Kr-85	31.6	0.961	
Kr-85m	62.8	35.5	7.23
Kr-87		0.00193	0.00280
Kr-88	0.0471	1.24	0.218
Rb-88	0.0566	1.57	0.0130
Sr-85		0.00919	
Sr-89	0.0000599	0.0442	0.0000352
Sr-90	0.00000359	0.0859	0.0000391
Sr-91	0.0000252	0.0000426	0.00000657
Nb-95	0.00000182	0.00000450	
Mo-99	0.0000805	0.00000135	0.00000110
Ru-103	0.000000700	0.000417	0.0000000951
Ru-106		0.00000408	0.00000723
Sb-124	0.00000266		
Sb-125			0.00000155
Te-132		0.0000239	
I-131	0.118	0.300	0.0555
I-132	0.00346	0.00765	0.00170
I-133	0.0749	0.107	0.0213
I-134	0.00270	0.00000197	0.0000238
I-135	0.00105	0.00388	0.0284
Xe-131m	12.1	1.30	6.88
Xe-133	26300.	9820.	2860.
Xe-133m	33.2	3.73	3.51
Xe-135	322.	338.	86.9
Cs-134	0.000280	0.0000226	
Cs-137	0.000593	0.000306	
Cs-138	0.0000934	0.00164	0.0133
Ba-139	0.00000380	0.00000505	0.00000854
Ba-140	0.0000494	0.0329	0.0000679
La-140	0.00000762	0.0000500	0.0000570
Ce-141	0.000171		0.00000700
Np-239	0.000000457		

Table V-3

Total Liquid Effluents (in Curies) Released by the Calvert Cliffs Nuclear Power Plant as Reported by BG&E (1-6)

Radionuclide	1978	1979	1980
Tritium	456.	514.	491.
Dissolved Noble Gases[a]	7.91	15.6	15.8
Other	5.98	7.77	4.79
Total Curies	469.89	537.37	511.59
Na-24	0.00511		
Ar-41	0.000170		
Cr-51	0.770	0.638	0.737
Mn-54	0.130	0.112	0.0867
Mn-56	0.0000236	0.000659	0.00124
Fe-59	0.0593	0.0300	0.00737
Co-57	0.00271	0.00645	0.000817
Co-58	1.97	3.81	2.00
Co-60	0.462	0.325	0.441
Zn-65	0.0000651		0.0240
Kr-85m	0.000885	0.0000748	0.000179
Kr-87		0.000565	
Sr-85	0.000600	0.000724	
Sr-89	0.0244	0.00109	0.0141
Sr-90	0.00387	0.000989	0.0230
Sr-91			0.000613
Nb-95	0.158	0.0163	0.0384
Zr-95	0.162	0.147	0.212
Zr-97	0.000845	0.00112	0.000584
Mo-99	0.111	0.0122	0.00873
Ru-103	0.0376	0.0252	0.0248
Ru-106	0.00369	0.0126	0.000733
Cd-109		0.000102	
Ag-110m	0.0440	0.0953	0.0301
Sn-113		0.00181	0.243
Sb-124	0.0135	0.0329	0.0167
Sb-125	0.187	0.268	0.205
Te-129		0.000172	
Te-132	0.00219		
I-131	0.498	0.648	0.158
I-132	0.00906	0.0118	0.00162
I-133	0.384	0.391	0.0695
I-135	0.00753	0.0345	0.00703
Cs-134	0.308	0.394	0.106
Cs-136	0.0174	0.00318	
Cs-137	0.465	0.568	0.183
Xe-131m	0.00644		
Xe-133	7.20	15.1	15.5
Xe-133m	0.204	0.0952	0.106
Xe-135	0.498	0.420	0.210
Xe-135m		0.00423	0.00322
Xe-138		0.000109	
Ba-140	0.0452	0.0185	0.00605
La-140	0.0677	0.133	0.0313
Ce-141	0.00751	0.00563	0.00269
Ce-144	0.00181		
Np-239	0.0214		
Unidentified		0.0271	0.104

(a) Noble Gas Totals are the summations of the listed noble gas isotope activities.

Table V-4

Radiological Monitoring Conducted by the Baltimore Gas & Electric Company in the Vicinity of the Calvert Cliffs Nuclear Power Plant

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES
Aquatic			
Finfish	Quarterly	1	
Flesh			Gamma
Bone			Sr-89/90
Shellfish			
Crabs (Flesh)	Quarterly	3	Gamma
Oysters (Flesh)	Quarterly	2	Gamma
Sediment	Quarterly	4	Gamma, Sr-89/90
Bay Water	Monthly	2	H-3, Gamma, Sr-89/90
Atmospheric			
Air			
Iodine	Weekly	4	I-131
Particulates	Weekly	7	Gamma, Gross Beta, Sr-89/90
Precipitation	Continuous	1	Gamma, H-3, Gross Beta, Sr-89/90
Terrestrial			
Vegetation	At Harvest	3	Gamma, Sr-89/90[a]
Soil	At Harvest	3	Gamma, Sr-89/90
Groundwater	Quarterly	4	H-3, Gamma
External radiation	Monthly	14[b]	TLD

(a) Analysis of cured or dried sample
(b) Includes Baltimore, Md. as a control station

Table V-5

Radiological Monitoring Conducted by the
Maryland Department of Health and Mental Hygiene
in the Vicinity of the Calvert Cliffs Nuclear Power Plant

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES
Aquatic			
Shellfish			
Oysters	Quarterly	1	Gamma
Sediment	Quarterly	1	Gamma
Bay Water	Quarterly	3	Gamma, H-3
Atmospheric			
Air			
iodine	Weekly	4[(a)]	I-131
particulates	Weekly	4	Gamma, Gross Beta,
Terrestrial			
Vegetation	At Harvest	1	Gamma[(b)]
Groundwater	Quarterly	15	Gamma, Gross Beta, H-3
External radiation	Monthly	12	TLD

(a) In addition to these, a Baltimore location serves as a control
(b) Analysis of cured or dried sample

Table V-6a

Radiological Monitoring of Aquatic Impact Conducted by the Maryland Power Plant Siting Program in the Vicinity of the Calvert Cliffs Nuclear Power Plant

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES[a]
Shellfish			
Oysters			
Natural bar	Quarterly	2	Gamma, Sr-89/90
Discharge tray	Quarterly, Semi annually, triquarterly, annually	1	Gamma, Sr-89/90
Crab	Spring,fall	2	
Shell			Gamma, Sr-89/90
Flesh			Gamma, Sr-89/90
Clams (Flesh)	Nonroutine	2	Gamma
Finfish			
Forage species	Spring,Fall	2	
Whole			Gamma, Sr-89/90
Edible species	Spring,Fall	2	
Flesh			Gamma, Sr-89/90
Bone			Sr-89/90
Waterfowl	Winter	2	
Flesh			Gamma, Sr-89/90
Bone			Sr-89/90
Grass shrimp	Spring,Fall	2	Gamma, Sr-89/90
Algae	Spring,Fall	2	Gamma, Sr-89/90
Miscellaneous biota (zooplankton benthos, etc.)[b]	Spring,Fall		Gamma, Sr-89/90
Sediments	Quarterly,	14	Gamma, Sr-89/90
	Annually	24	Gamma, Sr-89/90

(a) Routine Sr-89/90 analysis initiated in 1980.
(b) Routine quarterly epifauna program initiated in 1981.

Table V-6b

Radiological Monitoring of Terrestrial Impact Conducted by the Maryland Power Plant Siting Program in the Vicinity of the Calvert Cliffs Nuclear Power Plant

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES[a]
Vegetation crops	At harvest	2	Gamma, Sr-89/90[b]
Lichens, leafy vegetables, lawn grass, pasture grass, etc.	(c)	(c)	Gamma, Sr-89/90
Soils	(c)	2 $\leq$12	Gamma, Sr-89/90 Sr-89/90
External radiation	Monthly	11[d]	TLD

(a) Routine Sr-89/90 analysis initiated 1980.
(b) Analysis of freshly harvested sample
(c) Non-routine collection to determine specific radiological impact as required.
(d) This program is integrated with DHMH, however, these 11 are in addition to those listed in Table V-5.

with this weapons test were also detected in air particulates at this time (11). In April 1979, DHMH detected a trace atmospheric concentration of I-131 (10 ± 7 fCi/m^3) in the Calvert Cliffs area. This is probably not due to releases by the plant, but is more likely from a remote source (Peach Bottom, TMI) since I-131 was also detected in the atmosphere (11), and in milk (12) in the Peach Bottom vicinity during this period.

As is the case with I-131, Sr-89 and Sr-90 are produced in weapons test explosions as well as power plant operation, and therefore can be introduced into the environment by both weapons test fallout and routine power plant releases. The longer lived Sr-90 has been historically present throughout Maryland, and was not detected in the Calvert Cliffs vicinity at levels significantly higher than those of farfield locations. Sr-89 attributed to power plant operation, however, was detected in air particulates at Calvert Cliffs during the third quarter of 1979 (9). Sr-89 was also detected in soil samples from both Calvert Cliffs and farfield locations in March 1978 (8), and was attributed to the March 1978 Chinese weapons test. The environmental impact of Sr-89 at the very low concentrations detected is inconsequential. Precipitation samples contained no plant-related gamma radionuclides or Sr-89/90, and tritium values were consistent with fallout-associated levels.

No plant-related radionuclides were detected in crop vegetation in 1978. In 1979 a sunflower sample analyzed by BG&E indicated the presence of a low concentration of Sr-89 which may have been the result of plant operation. Sr-90 detected by BG&E in tobacco in concentrations up to 1.8 nCi/kg (wet) may also be plant related. This value is somewhat in question because it varies significantly (on the high side) from the other data. BG&E personnel attribute this to improper laboratory technique (13), and data from other monitoring programs support questioning the validity of this number. Soil and tobacco collected in the fall of 1980, however, show no discernible Sr-90 increase in the vicinity of Calvert Cliffs (7). More detailed radiostrontium investigation is underway; PPSP and BG&E are analyzing fresh (uncured) tobacco and soils from both the plant vicinity and farfield locations in an attempt to detect any possible plant-associated increment.

In summary, of those radionuclides released to the atmosphere during 1978-1980 by the Calvert Cliffs Nuclear Power Plant, only Sr-89 and a trace of I-131 were detected in the atmospheric and terrestrial environment. Detection of fallout from the 1978 Chinese weapons test confirmed the ability of the monitoring programs to discern other small, man-made increments of radioactivity in the airborne pathway. These concentrations provide context for evaluating the minor plant-associated increment, which is regarded as insignificant.

Aquatic Radionuclide Distributions

An annual average of approximately 500 Ci of tritium was released via the liquid pathway during the 1978-1980 period. This represents approximately 96 percent of the activity released to the aqueous environment. Monitoring of Chesapeake Bay water by BG&E and the State occasionally reveals tritium concentrations above the background levels ~1500 pCi/l (11). These higher concentrations, attributed to routine releases by the plant, are localized in the discharge vicinity. Because of dilution and dispersion, tritium concentrations in Bay water outside the immediate discharge area are at background levels. Because tritium is not a bioaccumulated radionuclide, the resulting radiation doses to aquatic biota are insignificant, and no adverse environmental impact is associated with these levels.

Radionuclides with potentially significant environmental impact are those which may, through chemical and biological processes, be retained and accumulated in the Chesapeake Bay ecosystem. Cycling and trophic level assimilation of these radionuclides will provide an additional radiation dose to Bay organisms, and could ultimately contribute some radiation dose to man.

A variety of such bioaccumulable radionuclides have been introduced into the Bay as a result of atmospheric weapons testing. Since 1978, three Chinese atmospheric detonations have produced detectable concentrations of fallout in Bay samples. The relatively short-lived Ce-141, Ce-144, Ru-103, Ru-106, Zr-95 and Nb-95 are episodically detected in sediments and finfish following these events and during the annual Spring washout of weapons-test debris. The long-lived fallout product Cs-137 is ubiquitously distributed in the environment and is consistently detected in sediments and biota of the Chesapeake Bay. Calvert Cliffs also discharges small quantities of these radionuclides. However, concentrations detected in environmental samples collected near the plant are within the statistical distribution of concentrations present in the same media at locations beyond the plant's influence. The plant-related contributions are indistinguishable and therefore not quantifiable. These very low levels of fallout radionuclide concentrations are insignificant contributors to the dose received by Bay biota and human consumers.

Other radionuclides which are not fallout constituents, but are routinely released by Calvert Cliffs, have been detected in Bay samples (7-10, 14). Nearfield biota and sediments periodically contain low levels of Co-58, Co-60, Zn-65, and Ag-110m. Because of the physically and biologically dynamic character of the Chesapeake Bay Estuary, and variations in radioactivity released by the plant, radionuclide concentrations within individual sample media vary greatly. Table V-7 presents maximum concentrations of plant-associated radionuclides detected in the PPSP monitoring program.

Naturally ocurring radionuclides of the thorium and uranium decay products and potassium-40, as well as weapon test fallout radionuclides, are present in sediments in the Calvert Cliffs area and throughout the Bay. Radionuclides detected in sediments which are attributed to Calvert Cliffs are Co-58, Co-60, and Ag-110m. Ag-110m was detected at extremely low levels in nearfield sampling locations through November 1979, but not later (7, 15). Co-58 and Co-60 have been detected consistently in area sediments during the reporting period (1978-1980). Prior to 1978, Co-58 was not detected in sediments and Co-60 was present at a barely detectable concentration at one sampling location. The Co-60 detected at that time may not be related to Calvert Cliffs since it was found in sediments prior to plant operation (15). Concentrations of Co-58 and Co-60 in sediments fluctuate over time, but a constant localized increase of radiocobalt in area sediments is not apparent. However, the increased incidence of Co-58 at the transect extremes (7) indicates an expansion of the impact area.

Table V-7

Maximum Concentrations of Radionuclides Attributed to Calvert Cliffs Operation in Various Environmental Media for the Period 1978-1980 as Determined by PPSP Monitoring Program Counting Uncertainty @ 95% Confidence Level

MEDIA	Radionuclide Concentration (pCi/kg, wet)[a] Co-58	Co-60	Zn-65	Ag-110m
Seaduck				
Flesh	11±9	-	-	-
Gut	472±38	50±24		
Edible Finfish	-	-	-	-
Forage Finfish[b]	186±4	15±2	-	3±2
Oysters	73±4	6±2	31±6	350±20
Clams (<u>Mya arenaria</u>)	3±3	2±2	-	65±6
Crab				
Meat	-	-	-	22±6
Shell	-	-	-	119±32
Grass Shrimp				25±11
Zooplankton	28±6	5±5	-	-
Algae	141±14	3±8	-	-
Sediment				
Sand	287±11	33±6	-	9±5
Clay	450±14	179±16	-	13±7

(a) Concentrations for crab shell and sediments are in pCi/kg, dry. Concentrations for zooplankton are in pCi/l.

(b) This collection of menhaden also contained 82±15 pCi/kg Cr-51 and 8±3 pCi/kg of Fe-59.

The mobile and transitory nature of finfish results in a short term exposure to Calvert Cliffs discharges. This reduces the extent to which these species can assimilate discharged radioactivity through direct uptake or food chain transport. Resident benthic and epibenthic biota such as clams and oysters which are present (and therefore exposed) year-round are impacted to a greater extent and serve as indicators of upper concentration limits. Macro-algae and fouling organisms which are present or metabolically active on a seasonal basis reflect shorter term radioecological impact.

Edible finfish (primarily bluefish) collected in the Calvert Cliffs vicinity have contained fallout-attributed Cs-137 but no detectable power plant-related radionuclides (7-10). Samples of certain forage finfish (anchovies and silversides) have likewise contained no detectable power plant radioactivity. Radionuclides attributed to the plant have, however, been detected on occasion in the filter-feeding menhaden, a primary prey species for important predator finfish, e.g., bluefish and weakfish (7). The presence of the short-lived Cr-51 (half-life 28 days) and Fe-59 (half-life 45 days) in these samples indicates that the population was in the nearfield during a discharge, and collection and analysis took place soon after exposure to and uptake of, the released radioactivity.

Radionuclides attributed to Calvert Cliffs have been detected in shellfish: periodically in blue crabs (7) and consisently in oysters (8-10, 14). As previously mentioned, oysters resident in the Calvert Cliffs vicinity are exposed to radioactivity to a greater extent than transient biota such as finfish and crabs, and may provide a higher potential dose to man through seafood consumption. PPSP monitors oysters from a natural bed 3/4 mile north of the discharge, and conducts a submerged tray study in which groups of oysters are exposed directly to Calvert Cliffs discharges for selected time periods. The assimilation and depuration of radionuclides in oysters is affected not only by the availability of radionuclides, but also a multitude of chemical and biological conditions. The tray study provides a more thorough understanding of the controlling parameters than is possible through quarterly monitoring of the natural bed. Significantly, this study indicated that uptake was totally inhibited during the winter season (14). The most noteworthy radionuclide present in oysters during the previous period was Ag-110m (16). Concentrations of Ag-110m in continuously exposed oysters peaked in the fall of 1977 at approximately 600 pCi/kg (wet) (17) and have been decreasing throughout the 1978-1980 period to approximately 60 pCi/kg (wet) (8-10, 14). As of this publication date, concentrations were ~20 pCi/kg (wet) (7, 11). Evidence of the sensitivity of using oysters as biological indicators of potential radioecological impact is provided by the fact that very low levels of Zn-65 are sporadically detected in these organisms (11, 14) while the quantities of this radionuclide remain so low as to be undetectable by BG&E in their analysis of releases.

Sea ducks (Old Squaw) collected in the discharge vicinity have contained Co-58 associated with plant releases (7). These birds overwinter on the Bay and feed extensively on small clams found in the Calvert Cliffs area. While these low levels have no significant radiological impact, they serve to demonstrate upper trophic level assimilation of power plant radioactivity.

Radiation Dose to Man

The estimate of the dose commitment[1] to an individual consuming seafood harvested in the vicinity of Calvert Cliffs has been calculated using the maximum radionuclide concentrations detected in shellfish taken from this area (Table V-7). Calculated dose commitments to adults, teenagers and children are given in Table V-8. Table V-9 contains a comparison of doses predicted in the Final Environmental Impact Statement for CCNPP and those doses calculated using the maximum concentrations from Table V-8.

Summary

Of the radioactivity detected via monitoring of the atmospheric pathway during 1978-1980, only Sr-89 detected at low levels in air particulate and vegetation samples was attributed to plant operation. A trace of atmospheric I-131 may be plant related, or due to releases from a remote source. At these levels, environmental impact is negligible.

Radioactivity dicharged via the aqueous pathway has been detected in the Chesapeake Bay ecosystem. Sediments have contained low levels of Co-58, Co-60, and Ag-110m. Ag-110m has not been detected in sediments since 1979. Co-58, which had not been detected prior to 1978, is consistently found in area sediments. The range of concentration varies over time, and while no significant build-up is apparent in the nearfield, sediment dispersion appears to be expanding the impact area.

Radionuclides attributed to aqueous releases by Calvert Cliffs have been detected at low levels in all sampled Bay biota with the exception of edible predator finfish. The maximum detected concentrations would result in radiation doses to the various organisms which are still orders of magnitude lower than doses resulting from naturally radioactive sources present in the Bay environment such as thorium and uranium decay products and potassium-40. Due to their year-round residence, oysters in the Calvert Cliffs vicinity represent the greatest potential human radiation dose through seafood consumption. Employing the maximum detected concentration in seafood, the estimated dose to the maximum exposed individual through consumption would be 0.11 mrem to an adult's G.I. tract. The plant operates well within 10 CFR 50 Appendix I design criteria which limit a maximum exposed individual to 3 mrem annually per reactor for the aqueous pathway.

B. Peach Bottom Atomic Power Station

The Peach Bottom Atomic Power Station (PBAPS), owned and operated by the Philadelphia Electric Company (PECO), is located approximately three miles north of the Pennsylvania-Maryland border on the Susquehanna River. Although it is outside Maryland, it has the potential for impact in Maryland because

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[1]The dose commitment from the ingestion of a given quantity of some radionuclide is the total dose that will be received by the individual before the radioactive material is removed from the body by excretion and/or radioactive decay. These estimates employ Regulatory Guide 1.109 dose conversions (24).

Table V-8

Maximum Dose Commitment in mrem to an Individual Consuming Shellfish[a] Exclusively from the Vicinity of the Calvert Cliffs Nuclear Power Plant (Utilizing Radionuclide Concentrations Given in Table V-7)

	Age Group	Adult	Teen	Child
Quantity Consumed[b]	Oysters	29 dozen	22 dozen	10 dozen
	Clams	29 dozen	22 dozen	10 dozen
	Crabs	15 dozen	11 dozen	5 dozen
Total Body Dose	Co-58	.000610	.000621	.000684
	Co-60	.000142	.000144	.000159
	Zn-65	.001079	.001099	.001196
	Ag-110m	.000154	.000157	.000173
	TOTAL	.00198	.00202	.00221
Bone Dose	Co-58	(c)	(c)	(c)
	Co-60	(c)	(c)	(c)
	Zn-65	.000750	.000679	.000722
	Ag-110m	.000280	.000273	.000321
	TOTAL	.00103	.00095	.00104
Liver Dose	Co-58	.000272	.000270	.000223
	Co-60	.000064	.000064	.000054
	Zn-65	.002387	.002356	.001924
	Ag-110m	.000259	.000258	.000217
	TOTAL	.00298	.00295	.00242
Kidney Dose	Co-58	(c)	(c)	(c)
	Co-60	(c)	(c)	(c)
	Zn-65	.001597	.001508	.001212
	Ag-110m	.000509	.000492	.000403
	TOTAL	.00211	.00200	.00162
GI-LLI Dose	Co-58	.005511	.003717	.001303
	Co-60	.001206	.000834	.000299
	Zn-65	.001504	.000998	.000338
	Ag-110m	.105700	.072485	.025764
	TOTAL	.11392	.07803	.02770

(a) No power-plant radioactivity has been detected in edible finfish.
(b) The numbers of each type of shellfish consumed corresponds to 5kg/yr, 3.8kg/yr, and 1.7kg/yr for an adult, teen, and child, respectively. These are recommended values (Reg. Guide 1.109) used in lieu of site specific data to determine the dose commitment to the maximum exposed individual.
(c) Dose/concentration conversion factors not available.

Table V-9

Comparison of Predicted[a] and Calculated[b] Dose Commitments in mrem to a Maximum Exposed Individual from Consuming Seafood Exclusively from the Vicinity of the Calvert Cliffs Nuclear Power Plant

Seafood	Total Body		G.I.-LLI Tract		Thyroid		Bone	
Consumed	Predicted	Calculated	Predicted	Calculated	Predicted	Calculated	Predicted	Calculated
Finfish	0.037	(c)	0.078	(c)	0.087	(c)	0.021	(c)
Crustacea	0.20	0.000017	1.62	0.011960	0.22	(d)	0.022	0.000032[e]
Molluscs	0.043	0.003571	0.42	0.205058	0.22	(d)	0.037	0.001854[e]

(a) Predicted doses taken from the Final Environmental Impact Statement for Calvert Cliffs (18).

(b) Calculated doses are derived assuming an annual consumption of 18 kg of finfish, and 9 kg of crustacea or molluscs; radionuclide concentrations utilized are those found in Table V-7.

(c) No power plant radionuclide have been detected in edible finfish.

(d) Thyroid dose conversion factors not available.

(e) These values include no dose commitment for Co-58 or Co-60 as conversion factor were unavailable for these isotopes.

of its location on the Susquehanna River. Each of the two units remaining in operation (Unit 1, a 40 MWe High Temperature Gas Cooled Reactor, was decommissioned in January 1975) is a boiling water reactor with a maximum dependable capacity of 1098 MWe.

Unit 2 of the PBAPS, placed in commercial service in July 1974, had produced 42,405,440 MWh gross of electrical energy as of the end of 1980. Unit 3, placed in commercial service in December 1974, had produced 39,745,940 MWh gross. Since the inception of commercial operation, Units 2 and 3 have achieved cumulative unit capacity factors of 62.3% and 62.7%, respectively.

Releases to the Environment

Radionuclides discharged to the atmosphere and the Conowingo Pond (Susquehanna River) from the Peach Bottom Atomic Power Station as reported by PECO during 1978-1980 are given in Tables V-10 and V-11. Noble gasses, chiefly the Xenon isotopes, comprise nearly 100 percent of the radioactivity released to the atmosphere. These radioisotopes have very little environmental impact due to their inert nature. Iodine-131, which is an isotope of environmental significance, is routinely released in small quantities. Actual releases to the atmosphere for the three year period are considerably lower than estimated in the Final Environmental Impact Statement for Peach Bottom (18).

Of the liquid releases, tritium and dissolved noble gases accounted for about 70 percent and 10 percent, respectively, of the total activity released during the three year period. Environmentally significant radionuclides (other than tritium and noble gases) accounted for about 20 percent of the total activity released over the three year period, with I-131, Co-60, Zn-65, Cs-134 and Cs-137 being of primary importance. Due to the short half-lives of the Iodines, they are only sporadically detected in the aquatic environment and do not accumulate in environmental media. Co-60, Zn-65, Cs-134, and Cs-137 are consistently detected in Conowingo Pond sediments. Zn-65, Cs-134 and Cs-137 are routinely detected in biota of the Conowingo Pond, Susquehanna River, and Susquehanna Flats.

Environmental Monitoring Programs

PECO, the Maryland DHMH, and PPSP all conduct extensive monitoring programs to assess the impact of PBAPS. To define the atmospheric pathway impact, PECO contractors analyze samples of air, precipitation, terrestrial vegetation, soils, and milk. Monitoring of ambient radiation levels provides an assessment of the external dose delivered by noble gasses through the atmospheric pathway. The DHMH maintains air particulate and air iodine samplers in the Peach Bottom vicinity for assessing atmospheric impact, and conducts jointly with PPSP an ambient radiation monitoring program.

The utility's aquatic environmental monitoring program is designed to quantify radionuclide concentrations in water, sediment and finfish. Sampling is restricted to the Conowingo Pond except for a spring collection of shad from the Conowingo Dam tailrace; Maryland impact beyond the Conowingo Dam is

Table V-10

Total Gaseous Releases (Curies) from the Peach Bottom Atomic Power Station as Reported by PECO (19-24)

Radionuclide	1978	1979	1980
Tritium	20.0	27.3	12.9
Noble Gases	49700.	122500.	12900.
Halogens	1.44	1.36	1.14
Other	0.038	0.122	0.096
Total Curies	49721.478	122528.782	12914.136
Na-24	0.000437	0.00249	
Cr-51	0.000288	0.000674	
Co-58			0.0000825
Co-60	0.00469	0.000940	0.00870
Zn-65	0.00310	0.000853	0.0151
Kr-85	1.91		
Kr-85m	66.6	433.	16.6
Kr-87		112.	3.72
Kr-88		84.9	6.13
Rb-88		0.0103	0.00356
Rb-89		0.000379	0.0000746
Y-91m	0.000917	0.00247	0.00318
Sr-89	0.00241	0.00209	0.00210
Sr-90	0.000106	0.0000927	0.0000659
Sr-91	0.00220	0.000326	0.00145
Sr-92		0.0000426	
Mo-99	0.0000747		
Tc-99m		0.00121	
Ag-110m	0.000156		
I-131	0.0839	0.258	0.0294
I-133	0.645	0.631	0.569
I-135	0.711	0.475	0.543
Cs-134	0.000570	0.00165	0.00177
Cs-137	0.000942	0.00152	0.00450
Cs-138	0.0211	0.0962	0.0535
Xe-131m		136.	
Xe-133	45440.	106000.	11000.
Xe-133m	4197.	194.	115.
Xe-135		15400.	1600.
Xe-135m		86.9	76.5
Xe-138		23.1	107.
Ba-140	0.0000855	0.000334	0.00129
La-140	0.00104	0.000188	0.000925
Np-239	0.0000687		

Table V-11
Total Liquid Releases (Curies) from the Peach Bottom
Atomic Power Station as Reported by PECO (19-24)

Radionuclide	1978	1979	1980
Tritium	32.4	42.7	37.3
Dissolved Noble Gases	7.10	6.53	1.35
Other	9.78	21.10	3.65
Total Curies	49.28	73.33	42.30
Na-24	4.45	9.27	0.578
P-32		0.0719	0.0170
Cr-51	0.00445	0.0649	0.0965
Fe-55		0.203	0.0220
Mn-54	0.0879	0.00735	0.00879
Mn-56			0.000627
Co-58	0.0273	0.0240	0.0234
Co-60	0.155	0.162	0.156
Ni-63		0.0319	0.00511
Zn-65	0.424	0.460	0.306
Kr-85m		0.0528	0.000403
Kr-87		0.0298	
Kr-88		0.0851	
Y-91m		0.0230	0.0139
Sr-89	0.0189	0.0202	0.00757
Sr-90	0.000944	0.000813	0.000380
Sr-91		0.00763	0.00711
Sr-92	0.000127	0.00142	0.000734
Nb-95		0.000471	0.000570
Zr-95			0.000416
Mo-99	0.000416	0.000160	
Te-99m	0.00262	0.101	0.0218
Ru-103		0.000177	
Cd-109		0.0858	0.00171
Ag-110m		0.000114	
Sb-122		0.194	
Sb-124		0.000536	0.0000315
Te-132	0.0505	0.0151	0.0238
I-131	0.227	0.964	0.0639
I-132	0.00746	0.00322	0.000784
I-133	0.300	0.446	0.0721
I-134	0.136		0.000721
I-135		0.118	0.0236
Xe-131m		0.103	0.0185
Xe-133		1.17	0.313
Xe-133m		0.000718	0.00222
Xe-135		3.08	0.521
Xe-135m	0.103	0.0185	
Xe-133		1.17	0.313
Xe-133m		0.000718	0.00222
Xe-135		3.08	0.521
Xe-135m		0.0705	0.0546
Cs-134	2.86	3.92	0.568
Cs-137	0.810	3.26	0.691
Ba-140		0.000963	0.00740
La-140		0.0237	0.0107
Np-239	0.115	0.0286	0.0116

not addressed. PPSP conducts an extensive monitoring program to assess the actual distribution of PBAPS radionuclides, focussing on the aquatic environment because this pathway has the greatest potential for a significant impact in Maryland. Samples are collected from Conowingo Pond, the Susquehanna River and the Upper Chesapeake Bay to determine radionuclide concentrations in sediments, aquatic vegetation, forage and commercially significant finfish, shellfish, waterfowl and aquatic mammals (Figure V-1). The programs conducted by the three agencies, described by sample type, collection frequency and type of analysis, are presented in Tables V-12, V-13, V-14, and V-15.

Atmospheric and Terrestrial Radionuclide Distributions

Except for I-131, relatively small quantities of environmentally significant radioactivity are released via the atmospheric pathway, a fact which is supported by the general lack of detectable PBAPS radionuclides in atmospheric and terrestrial samples. TLD measurements indicate that the ambient radiation level is no higher in the PBAPS vicinity than at farfield locations (12, 25, 26). The frequent detection of natural and weapons test fallout radioactivity in air particulate, precipitation, soil and milk samples demonstrates the efficacy of the surveillance network. Cosmically-activated Be-7, the ubiquitous and routinely detected Cs-137, and the episodically present Zr-95 and Nb-95 are natural and weapons test fallout products whose concentrations peak with seasonal precipitation and atmospheric washout (11, 12, 25-29).

In March 1978, an atmospheric weapons test by the Peoples Republic of China produced detectable fallout, which included I-131, in the Peach Bottom vicinity (11, 25) as well as at farfield locations (11). Some, or all of the I-131 detected at this time in milk and air particulates (by PECO contractors), and in atmospheric and particulate samples (by DHMH) can be attributed to this event, since fresh fission radionuclides (I-132/Te-132, Ba/La-140) were also in evidence (11). PBAPS did release I-131 in April (the fifth highest monthly I-131 release over the 3 year subject period, 20.5 mCi) and may also have been an unquantifiable contributor to the detected concentrations. PECO contractors again detected I-131 in milk later in the year (October and November), an event which is attributed solely to releases by PBAPS (25). The maximum detected spring concentration in milk was 9.1 ± 0.9 pCi/l, and in the fall, 0.84 ± 0.08 pCi/l.

In 1979, I-131 was detected in milk in the Peach Bottom vicinity throughout the month of April to a maximum concentration of 0.53 ± 0.06 pCi/l (26). The Maryland DHMH (11) also detected I-131 in air samples from Harford County in the second and third weeks of April (Maximum of 30 ± 10 fCi/m^3)[1]. The TMI accident in late March and subsequent atmospheric releases has been regarded as the source of this I-131 because similiar levels were present in milk from near and distant farms suggesting a regional effect from a distant source (26). However it should be noted that the second highest total monthly release of I-131 from PBAPS for the three-year subject period also

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[1]DHMH also detected a trace (10 ± 7 fCi/m^3) of I-131 in the atmosphere in the Calvert Cliffs area during the second week of April which may be due to TMI, PBAPS, Calvert Cliffs or a combination.

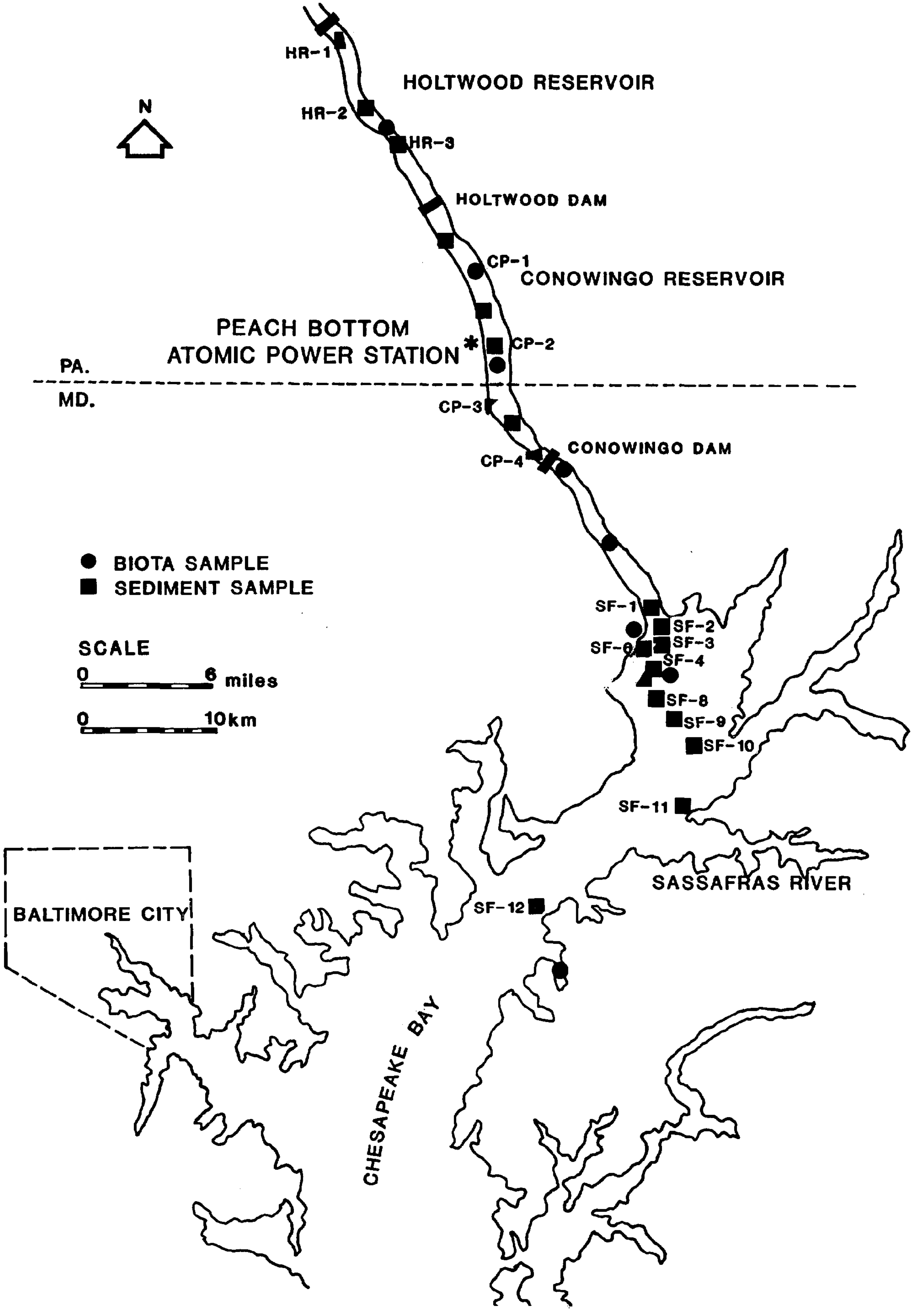

Fig. V-1. PPSP Susquehanna River/Upper Bay Sampling Locations

Table V-12

Radiological Monitoring Conducted by
Philadelphia Electric Contractor Interex Corporation
in the Vicinity of the Peach Bottom Atomic Power Station

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES
Air particulate	Continuous samples composited weekly/monthly	17	Gamma (monthly);, Gross Beta (weekly)
Precipitation	Continuously	3	Gross Beta; Sr-89/90, Cs-137
Milk	Quarterly	11	Gross Beta; Sr-89/90;Cs-134/137, I-131, K-40
Vegetation	Spring, summer, fall	7	Gross Beta; Sr-89/90; Cs-134/137,K-40
Soil	Semiannually	6	Gross Beta; Sr-89/90;Cs-134/137, K-40
Small mammal thyroid muscle bone	Semiannually	1	Gross Beta; I-131; Sr-89/90
Well water	Quarterly	4	Gross Alpha; Gross Beta; Cs-137; Sr-89/90
Surface water	Monthly	8	Gross Alpha; Gross Beta
Discharge water	Monthly	2	Gross Alpha; Gross Beta
Sediments	Semiannually	6	Gamma; Gross Alpha; Gross Beta;Cs-134/137
Finfish	Quarterly	5	Gamma; Gross Beta; Sr-89/90; K-40

Table V-13

Radiological Monitoring Conducted by Philadelphia Electric Contractor Radiation Management Corporation in the Vicinity of the Peach Bottom Atomic Power Station

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES
Air			
Particulate	Continuous samples composited weekly	2	Gross Beta (weekly), Gamma (monthly)
Iodine[a]	Continuous samples composited weekly	7	I-131
Precipitation	Continuous samples composited monthly	2	Gamma, Gross Beta
Milk	Weekly while cows on pasture, otherwise monthly; quarterly	11 8;3	I-131, Sr-89/90[b], H-3[c], Gamma[d]
Soil	Semiannually	3	Gamma, Sr-89/90
Ambient radiation	Monthly, quarterly	47	TLD
Well water	Quarterly	4	Gross Beta, H-3
Surface water	Monthly	9	Gamma, Gross Beta, H-3, Gross alpha[e]
Discharge water	Monthly	2	Gamma, Gross Beta H-3

(a) Initiated in March, 1980
(b) One farm
(c) Four farms
(d) One farm
(e) Four stations

Table V-14

Radiological Monitoring Conducted by the Maryland Department of Health and Mental Hygiene in the Vicinity of the Peach Bottom Atomic Power Station

SAMPLE MEDIA	NUMBER OF COLLECTION FREQUENCY	SAMPLING LOCATIONS	ANALYSES
Air			
particulates	Continuous samples composited weekly	2[b]	Gamma, Gross Beta, Gross Alpha[a]
iodine	Continuous samples composited weekly	2[b]	Gamma
Ambient radiation	Monthly	12	TLD
Surface water	Weekly	1	Gamma, Gross Beta, H-3

(a) PPSP initiated Sr-89/90 analysis on these samples in 1981.
(b) An additional, Baltimore location serves as control.

Table V-15

Radiological Monitoring Conducted by the Maryland Power Plant Siting Program in the Vicinity of the Peach Bottom Atomic Power Station

SAMPLE MEDIA	COLLECTION FREQUENCY	NUMBER OF SAMPLING LOCATIONS	ANALYSES
Mammals (muskrat, otter, raccoon)	Annual	2	
Flesh			Gamma, Sr-89/90
Bone			Sr-89/90
Waterfowl	(a)	2	
Flesh			Gamma, Sr-89/90
Bone			Sr-89/90
Finfish			
Forage species	Spring, Fall	4	
Whole			Gamma, Sr-89/90
Edible species	Spring, fall	4	
Flesh			Gamma, Sr-89/90
Bone			Sr-89/90
Shellfish			
Crabs (Flesh)	(a)	1	Gamma, Sr-89/90
Clams (Flesh)	(a)	1	Gamma, Sr-89/90
Oysters (Flesh)	(a)	1	Gamma, Sr-89/90
Mussels (Flesh)	Spring, fall	1	Gamma, Sr-89/90
Submerged Aquatic Vegetation	Spring, fall	3	Gamma, Sr-89/90
Sediments	Spring, fall	35	Gamma, Sr-89/90

(a) Non-routine collection to determine specific radiological impact as required.

occurred in March 1979 (42.3 mCi). It is possible that some fraction or all of the I-131 detected at this time was due to PBAPS releases. The third highest monthly release of I-131 for the subject period (39.3 mCi) occured in June and its presence in milk detected by RMC in June (max 0.65 ± 0.04 pCi/l) and July and August (max 0.06 ± 0.03 pCi/l) is attributed to releases by PBAPS during this period. In September and October, I-131 detected in milk to a maximum of 0.5 ± 0.1 pCi/l was attributed solely to PBAPS (26).

During 1980, I-131 was detected in milk in October, November and December by RMC (12) to a maximum concentration of 0.33 pCi/l. PBAPS released very little I-131 during this period; however, fallout from the Chinese weapons test on October 15 was reported by numerous agencies to have contributed I-131 throughout the mid-atlantic region. Maryland DHMH also detected I-131 in atmospheric samples at this time. The I-131 in milk in the PBAPS vicinity is attributed to this fallout event.

Other than I-131, radionuclides attributed to PBAPS atmospheric releases were detected only once during the 1978-1980 period at an onsite air monitoring station. Low levels of Co-60, Zn-65, Cs-134 and Cs-137 were detected at this location in air particulates in July 1980 (12).

Aquatic Radionuclide Distributions

As indicated in Table V-16, relatively low levels of radionuclides attributed to PBAPS have been detected in sediments, finfish, freshwater mussels, aquatic vegetation, waterfowl, and in one otter (30). While these low concentrations do not represent a human health concern, the diverse distribution of PBAPS radionuclides within the ecosystem is nonetheless confirmed.

Radionuclide concentrations in finfish are highest in the plant vicinity in the Conowingo Pond and in the Susquehanna River below the Conowingo Dam. Finfish collected from the Susquehanna Flats have occasionally contained PBAPS attributed radioactivity (Cs-134). The highest concentration of PBAPS radioactivity detected in submerged aquatic vegetation (SAV) occurred on the Susquehanna Flats (the closest sampling location for SAV); however, Cs-134 was found associated with an SAV (milfoil) sample from an area below the Sassafras River, some thirty miles from the PBAPS (30). Because of cesium's high affinity for organic material, it was likely bound to suspended particulate material attached to the sample, rather than actually incorporated in the SAV itself.

Freshwater mussels from the Flats have been found to contain Zn-65 and Cs-134 attributed to PBAPS discharges, while crabs and oysters from the Swan Point area (the northernmost distribution limit for oysters in commercial abundance) have contained no detectable PBAPS radioactivity. Fish-eating waterfowl (mergansers) from the Susquehanna below the Dam have contained PBAPS radioactivity; muskrats and raccoons collected from the Susquehanna River below the Dam have contained no radioactivity attributed to PBAPS; however, a river otter taken in the Sassafras River area in 1980 did contain a trace of Cs-134 attributed to aquatic releases by PBAPS (30). As these animals are known to travel considerable distances, it is not unlikely that radionuclide uptake took place during residence closer to PBAPS, e.g., on the Susquehanna Flats or in the Susquehanna River.

Table V-16

Maximum Concentrations of Radionuclides Attributed to Peach Bottom Atomic Power Station in Various Aquatic Media for the Period 1978-1980 as Determined Through PPSP Monitoring Program (30). Counting Uncertainty @ 95% Confidence Level

Media	Radionuclide Concentration (pCi/kg, wet)[a] CO-60	Zn-65	Cs-134	Cs-137[b]
Mammals				
Otter				
Flesh	-	-	2±3	22±5
Gut	-	20±11	-	14±6
Raccoon				
Flesh	-	-	-	23±8
Gut	-	-	-	135±16
Muskrat				
Flesh	-	-	-	21±7
Gut	-	-	-	-
Waterfowl				
Merganser				
Flesh	-	-	20±9	35±9
Gut	-	-	13±16	60±24
Finfish				
Edible Species	-	60±20	230±26	316±26
Forage Species	-	197±23	173±14	203±16
Invertebrates				
Crab				
Meat	-	-	-	-
Shell	-	-	-	8±14
Oyster (Meat)	-	-	-	-
Rangia cuneata	-	-	-	-
Elliptio complanata	-	17±6	24±3	27±4
Submerged Aquatic Vegetation	-	9±4	134±5	155±5
Sediment	70±2	132±20	796±62	967±18

(a) Concentrations for crab shell and sediments are in pCi/kg, dry.

(b) Primarily attributable to weapons testing fallout; however the detection of Cs-134 indicates that power plant produced Cs-137 is present as well.

Zn-65 has been detected in Conowingo Pond sediments, but not in samples from below the Conowingo Dam. Cs-134 and a generally unquantifiable concentration of Cs-137 have been detected in sediments from Conowingo Pond and the Upper Chesapeake Bay, distributed as far out as the mouth of the Sassafras River.[1] Maximum concentrations occur in the Pond and the mouth of the Susquehanna River (30).

Most of the radioactivity released to the Susquehanna River by the PBAPS is dispersed and diluted to an extent that it is undetectable in the environment. Some radionuclides, however, are incorporated within the Susquehanna River/Upper Chesapeake Bay ecosystem, and trophic-level transport is apparent. Periodic fluctuations in environmental radionuclide concentrations occur as functions of a multitude of parameters such as discharge rate, stream flow, organic loading, and organism metabolism. The range of radionuclide concentrations in the various environmental media reflect the total system, and assuming that the radioactive discharges from the plant do not vary significantly from year to year, maximum concentrations detected probably represent upper environmental concentration limits. In other words, there is no indication that a localized "buildup" of radioactivity is occurring over time.

Radiation Dose to Man

The principal contributor to dose via the airborne-to-food chain pathway is I-131 ingestion though milk consumption. Doses projected in the Final Environmental Impact Statement (FEIS) published by the Nuclear Regulatory Commission are unrealistically high as they assume far greater I-131 releases and subsequent concentrations in milk (0.2 µCi/l) than actually occur. (The maximum concentration detected during the subject period was due to fallout, and was 5 pCi/l or 5×10^{-6} µCi/l; the maximum attributed to PBAPS was 8×10^{-7} µCi/l.) Utilizing this maximum concentration detected during November 1978, and attributable to PBAPS, the maximum hypothetical dose from milk consumption would be 0.11 mrem to an infant's thyroid (25). Consumption of milk containing the maximum concentrations of I-131 ocurring during the 1979 period would have produced a dose to an infant thyroid estimated to be 0.11 mrem (26). The 1980 Chinese weapons test would have produced a maximum annual dose to an infant thyroid of 0.05 mrem through I-131 ingestion by milk consumption. These dose estimates are based on Regulatory Guide 1.109 consumption factors and dose conversions (31).

The annual adult total body dose associated with the consumption of drinking water is calculated for an individual consuming 2 liters of Conowingo Pond water daily, based upon the release radionuclides given in Table V-11. H-3, Cs-134, and Cs-137 would produce a dose of 0.14 mrem for an annual Susquehanna River low flow of 2500 cfs and 0.01 mrem under average

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[1] As noted in the previous table, Cs-137 is introduced into the environment not only by power plants, but also by fallout from nuclear weapons testing. Cs-134, however, is introduced into the environment exclusively as a result of power plant operation, and its presence infers that at least some percentage of the Cs-137 was contributed by the power plant. Because the two isotopes behave identically in the environment, the power plant Cs-137 increment may be estimated from the ratio of Cs-137 to Cs-134 in the plant discharge.

flow (36,000 cfs). Although these estimates exceed the doses projected by the FEIS for Peach Bottom of .03 mrem for low flow and .003 mrem for an average flow these levels are considered insignificant. It should be noted that the 0.14 mrem estimate is almost totally due to those cesium isotopes, which would in actuality be organically bound and settle out (hence the radiocesium concentrations in sediments) or be removed in drinking water treatment plants prior to ingestion. Doses calculated utilizing release data are therefore considered to be unrealistic overestimates. The other radionuclides listed in Table V-11 are insignificant contributors to dose.

The annual whole body dose commitment to an adult consuming the PBAPS radioactivity in finfish from the plant vicinity was predicted in Peach Bottoms FEIS to be 0.37 mrem (assuming 21 kg of finfish are consumed annually). The consumption of this quantity of finfish containing the maximum concentration detected by the PPSP study would result in a whole body dose commitment to an adult of 1.07 mrem/yr. Table V-17 summarizes dose commitments to an individual consuming finfish containing these maximum radionuclide concentrations. These values illustrate maximum ingestion doses and do not reflect actual conditions. Even these overestimates, however, indicate a trivial dose increment by comparison with that attributed to ingestion of natural radioactivity (~21 mrem/yr). More realistic estimates of ingestion dose commitments are provided by utilizing the mean of radionuclide concentrations detected in edible finfish by the PPSP study. These doses are in the range of 0.05 mrem/yr to 0.08 mrem/yr for consumption of fish from the Conowingo Pond and 0.29 mrem/yr to 0.40 mrem/yr for consumption of fish from the Conowingo Dam tailrace[1].

Summary

During the 1978-1980 period, atmospheric releases of radioactivity from the Peach Bottom facility produced detectable radionuclide concentration at low levels in an air particulate sample from an onsite location on only one occasion. I-131 was detected in cows' milk and air samples from the PBAPS vicinity on numerous occasions throughout the 1978-1980 period. The source of this radionuclide might be attributed to Chinese weapons tests during the spring of 1978, and the fall of 1980. Releases from TMI in the first week of April 1979 may have been a source of I-131 detected in the PBAPS vicinity about this time. I-131 detected in milk in the fall and winter of 1978, and June, August, September and October 1979 is attributed exclusively to atmospheric releases by PBAPS. PBAPS could also have been a source of I-131 detected during the weapons test fallout and TMI event episodes as well. Radiation doses associated with these low I-131 levels are nonetheless well within 10 CFR 50 Appendix I guidelines.

Liquid effluents containing PBAPS radionuclides have produced detectable concentrations of Zn-65, Cs-134 and Cs-137 in sediments and biota of the Conowingo Pond, the lower Susquehanna River, and the Upper Chesapeake Bay. Maximum concentrations in finfish occur in the Conowingo Pond and just below

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[1]The mean depends upon the manner in which samples without detectable radionuclide concentrations are treated in the calculation. The range estimated herein was developed by assuming that undetectable concentrations lie between zero and the mean of concentration actually detected.

Table V-17

Maximum Dose Commitment[a] in mrem for an Individual Consuming Seafood Affected by PBAPS Effluents Exclusively (Assume Finfish Radionuclide Concentrations Given in Table V-16). Calculations Based Upon Conversion Factors of USNRC Reg. Guide 1.109

Age Group	Adult	Teen	Child
Consumption:			
Finfish	21 kg/yr	16 kg/yr	6.9 kg/yr
Total Body Dose:			
Zn-65	.008770	.008957	.009398
Cs-134	.584430	.336352	.128547
Cs-137	.473810	.262406	.100716
TOTAL	1.067	0.608	0.239
Bone Dose:			
Zn-65	.006098	.005526	.005673
Cs-134	.300426	.308016	.371358
Cs-137	.528889	.566272	.712860
TOTAL	0.835	0.880	1.090
Liver Dose:			
Zn-65	.01940	.019200	.01511
Cs-134	.71484	.724960	.609408
Cs-137	.72332	.753344	.682340
TOTAL	1.458	1.498	1.307
Kidney Dose:			
Zn-65	.012978	.012288	.009522
Cs-134	.231357	.230368	.188853
Cs-137	.245532	.256339	.222360
TOTAL	0.490	0.499	0.421
GI Tract Dose:			
Zn-65	.012222	.008131	.002650
Cs-134	.001251	.009016	.003285
Cs-137	.014002	.010710	.004273
TOTAL	0.027	0.028	0.010

(a) The dose commitment from ingestion of a given quantity of a radionuclide is the total dose that will be received by the individual before the radioactive material is removed from the body by excretion and/or radioactive decay.

the Conowingo Dam. Maximum sediment concentrations occur in the Conowingo Pond and at the Susquehanna River mouth. The maximum dose resulting from the ingestion of finfish containing the highest recorded concentrations is estimated to be 1.5 mrem/yr to a teenager's liver.

The dose increment resulting from operation of PBAPS is within the 10 CFR 50 Appendix I design criteria, which limits a maximum exposed individual to 3 mrem per year per reactor for the liquid pathway. An assessment of these exposure levels is given some context by a comparison with dose from natural radiation background. In the Peach Bottom vicinity a dose to the total body and internal organs averages about 100 mrem per year. The Peach Bottom plant-related increment obtained by consuming Conowingo Pond water exclusively (2 liters/day) and Peach Bottom contaminated finfish exclusively (21 kg/yr) at the highest radionuclide concentrations would represent about 1 percent of the natural background radiation dose.

C. Three Mile Island

The Three Mile Island Nuclear Station (TMINS), owned by Metropolitan Edison Co, Pennsylvania Electric Co and Jersey Central Power and Light Co is operated by the GPU Nuclear Corporation. The plant is situated on an island in the Susquehanna River approximately 8 miles Southeast of Harrisburg, Pennsylvania. This location is about 30 air miles and approximately 42 river miles from the Maryland border. Each of its two units is a pressurized water reactor with a maximum dependable capacity of 840 MWe. Neither of these units has been in operation since the March 28, 1979 accident at Unit 2.

Unit 1 of the TMINS, placed in commercial service on September 2, 1974, has produced 25,484,330 MWh of gross electrical energy. Unit 2, placed in commercial service on December 30, 1978 and in operation for only 95 full power days prior to the accident, has produced 2,125,528 MWh of gross electrical energy.

Accident

The loss of coolant accident which occurred on March 28, 1979 (described in detail in several references, cf. ref. 32) produced a large volume of radioactive water. The containment building was flooded with approximately 750,000 gallons of highly radioactive water, and surface areas within the building were also contaminated. The Auxilliary and Fuel Handling Building was flooded by approximately 600,000 gallons of radioactive water. This water was not nearly as radioactive as that in the containment building since it never came in direct contact with the damaged fuel, and has since been cleaned by the EPICOR II decontamination system.

During the accident, some radioactive effluent was discharged to the Susquehanna River in order to prevent overflowing the Auxilliary and Fuel Handling Building sump. This discharge was via a usually "clean" pathway, and because of the potential for impact in Maryland, was a primary concern. Although the utility and the State of Pennsylvania had monitoring programs in place, PPSP and DHMH initiated monitoring to assess potential effects and environmental consequences in Maryland of these releases to the Susquehanna River.

Since the termination of these accidental liquid discharges PPSP has conducted an extensive program of radioecological monitoring and assessment in the Susquehanna River and Upper Chesapeake Bay in conjunction with its radiological monitoring program for Peach Bottom. The TMI event affirmed the need for continuing radiological sampling to provide baseline radioecological data for assessment of the potential and real impact of the TMINS on the Maryland environment.

Releases to the Environment

Radionuclides discharged to the atmosphere and Susquehanna River by the Three Mile Island Nuclear Station during 1978 and 1979 as reported by Metropolitan Edison are given in Tables V-18 and V-19. As a result of the March 28, 1979 accident, normal plant operation was terminated in 1979. Uncontrolled atmospheric discharges associated with the event are apparent through a comparison of the quantity of radioactivity released during the two years. The principal radionuclides released were isotopes of the noble gas Xenon, I-131 and I-133. Both Xe-133 and I-131 were detected in the environment by utility monitoring programs in place at the time of the accident. In the clean-up process, approximately 43,000 Curies of the noble gas Krypton-85 were vented from the Unit 2 containment building from June 28, 1980 through July 10, 1980.

During the accident, water containing higher than normal levels of radioactivity was discharged into the Susquehnna River (35, 37). The dissolved noble gas Xe-133 was detected in spot samples of river water as far downstream as Columbia, Pennsylvania (approximately 17 miles downstream) during the accident's early stages (38); however, TMI-attributed radionuclides were not detected in the Susquehanna River in Maryland. Water samples collected every two hours by DHMH at the Holtwood and Conowingo Dams (see Figure V-1) revealed only natural radioactivity. Numerous agencies in addition to Metropolitan Edison began monitoring the Susquehanna in the TMI discharge vicinity to check for accidental releases during clean up operations (39).

Atmospheric and Terrestrial Radionuclide Distributions

This section contains a discussion of the TMI radioactive discharges only as they affect Maryland. The results and interpretation of all monitoring activities conducted by various agencies following the TMI-accident are available elsewhere (11, 38, 40).

Atmospheric releases of radioactivity (principally Xenon isotopes and I-131) during and immediately following the accident were detected in the environment in Pennsylvania as well as in Maryland. During the period March 30 through April 1, the DHMH detected I-131 and Xe-133 in the atmosphere at fixed sampling locations in Harford County near the Pennsylvania border. The maximum recorded atmospheric concentration of I-131 was 90 ± 30 fCi/m^3. Iodine-131 was again detected in this region from April 11 through April 18 with a maximum concentration of 30 ± 10 fCi/m^3 (11). These incidents have been attributed to TMI, (26) although, as previousely mentioned, the Peach Bottom plant may have been a contributing source. I-131 detected subsequently in Harford

Table V-18

Total Gaseous Releases from the Three Mile Nuclear Station
as Reported by Met. Ed. (33-36)

Radionuclide	1978	1979
Tritium	234.	189.
Noble Gases	15700.	9940000.
Halogens	0.027	16.6
Other	0.111	0.002
Total Curies	15934.138	9940205.602
K-40	0.00172	
Ar-41	97.0	18.5
Co-58	0.0322	0.000871
Co-60	0.0000133	0.000123
Kr-85	0.439	0.113
Kr-85m	1.03	0.0893
Kr-88		0.000610
Sr-85		0.000000430
Sr-89	0.000000265	0.000109
Sr-90	0.00000143	0.0000329
Nb-95	0.00000555	0.0000179
Ru-103	0.0000547	0.0000545
Ru-106		0.0000985
I-131	0.0272	14.2
I-133		2.39
Cs-134	0.00897	0.00000996
Cs-136		0.000000246
Cs-137	0.0677	0.000377
Cs-138		0.0000166
Xe-131m	11.4	2.52
Xe-133	15400.	8210000.
Xe-133m	49.8	11900.
Xe-135	183.	1580000.
Xe-135m		141000.
Ba/La-140	0.00000545	0.000200

Table V-19

Total Liquid Releases from the Three Mile Island Nuclear Station as Reported by Met. Ed. (33-36)

Radionuclide	1978	1979[a]
Tritium	194	104
Dissolved Noble Gases[b]	0.358	0.054
Other	1.00	0.681
Total Curies	195.358	104.735
Na-24	0.0533	
Ar-41	0.00356	
Cr-51	0.00497	0.00889
Mn-54	0.0362	0.0123
Mn-56	0.00300	
Fe-59	0.00398	0.00152
Co-57	0.00000860	
Co-58	0.481	0.0786
Co-60	0.0204	0.0142
Zn-65		0.000394
Ga-72	0.000721	
Kr-85	0.000988	
Kr-88	0.000188	
Rb-88	0.000117	
Sr-89	0.00134	0.0775
Sr-90	0.00045	0.00475
Nb/Zr-95	0.0109	0.00358
Zr-97	0.000303	0.0000888
Mo-99	0.000502	0.0000471
Ru-103	0.000292	0.000284
Ag-110		0.00199
Ag-110m	0.0123	0.000198
Sb-122	0.000326	0.000159
Sb-124		0.000130
I-131	0.0235	0.369
I-133		0.0470
I-134	0.00963	
I-135	0.000608	
Xe-133	0.349	0.0534
Xe-133m	0.000809	
Xe-135	0.00337	0.000398
Cs-134	0.144	0.0115
Cs-136	0.000459	0.00158
Cs-137	0.191	0.0238
Ba/La-140	0.000690	0.0235
Ce-141	0.0000539	0.0000315
Ce-144	0.00102	
W-187	0.00251	0.000343

(a) Listed activities are for the first half of 1979.

(b) Noble Gas totals are the summations of the listed noble gas isotope activities.

County is attributed to Peach Bottom and weapons test fallout events (11). The deposition of atmospheric concentrations of I-131 produced low but detectable concentrations of this isotope in cows' milk in some Pennsylvania localities (25, 27) but not in Maryland (11).

During the TMI clean-up period, several agencies were involved in monitoring the impact of Kr-85 vented from the containment building. During this period the PPSP maintained a network of Beta-sensitive dosimeters along the Pennsylvania-Maryland border and in the TMI vicinity. No dose increment attributable to the venting was discernible in Maryland (41).

Aquatic Radionuclide Distributions

To evaluate the impact of TMI discharges in Maryland, the PPSP collected and analyzed a series of sediment and biota samples collected during the spring and summer of 1979, from the Susquehanna River between TMI and the mouth of the River, as well as from the Upper Chesapeake Bay. With the exception of Cs-137 attributable to fallout, no man-made radioactivity was detected in finfish or sediments collected upstream of the Peach Bottom influence. Sediment, finfish and other biota collected from below Peach Bottom (in the Conowingo Pond, Lower Susquehanna River and Upper Chesapeake Bay) contain man-made radionuclides attributed to both fallout and routine releases of radionuclides from Peach Bottom.[1]

Summary

Xe-133 and I-131 released to the atmosphere by TMI during the accident were detected at low levels in early April 1979 in air samples (11). I-131 was not detected in cows' milk in Maryland. Radionuclides attributed to TMI have not been detected in the Susquehanna River in Maryland. Continued DHMH surveillance and the extensive monitoring PPSP is conducting to characterize the radioecology of the lower Susquehanna River and Upper Chesapeake Bay will provide the necessary data base for evaluating the effect of any future releases from TMI. The plant is currently prohibited from discharging any accident-related water. The NRC's Final programatic Environmental Impact Statement (FPEIS) on decontamination (40) addresses potential effects of discharging decontaminated water.

The major issue associated with the discharge option is not an environmental or radiological concern, but rather the public's perception of the effects of such a discharge. This perception could result in consumer avoidance of Bay seafood products, severely damaging commercial and recreational fisheries.

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[1] It is recognized that some fraction of TMI-related radioactivity, particularly Cs-134 and Cs-137, would ultimately be deposited in the Upper Bay. However, the absence of any detectable concentrations in samples taken from the Holtwood Reservoir (upstream and beyond PBAPS influence) indicates that TMI has made no significant contribution to man-made radioactivity detected in Maryland.

The State of Maryland opposes any such discharge pending the completion, evaluation and public review of studies designed to assess the potential social and economic consequences of the discharge option. The Maryland position and PPSP assessment of the potential environmental effects of a processed water discharge are detailed in Appendix A to the FPEIS

D. Radiological Emergency Planning

While the greatest environmental impact associated with the operation of most power plants occurs during normal day-to-day operation, nuclear power plants are distinguished by their potential for severe environmental impact in the event of an accident. While there have been no accidents causing such an impact in Maryland (or at any nuclear power plant), there has been a heightened interest in the preparation of Radiological Emergency Plans to cope with any such accident. This was, of course, motivated by the accident at Three Mile Island.

Required by Federal regulations are both off-site and on-site Radiological Emergency Plans. Preparation of the off-site portion is the responsibility of the State, while the on-site portion is the responsibility of the utility company. Preparation of the State of Maryland Radiological Emergency Plan was underway prior to the accident at Three Mile Island, while BG&E had in effect a plan as required by its license.

The development of the State's plan was redirected, and vast revision necessary in the Company's plan as a result of the new Federal Regulations promulgated as a response to TMI. The Nuclear Regulatory Commission has published its Final Rule on Emergency Planning (42), and, in conjunction with the Federal Emergency Management Agency, has published plan development criteria for state, local and utility planners (43). Both on-site and off-site portions of the plan have been designed to comply with these regulations, and were successfully tested in the presence of Federal observers on November 17, 1981. This was a complete test of both the onsite and offsite portion of the Radiological Emergency Plan (REP) for the Calvert Cliffs Nuclear Power Plant, thereby involving the Baltimore Gas and Electric Company.

An important basis for planning is the concept of Emergency Planning Zones (EPZ), defined as "areas for which planning is needed to assure that prompt and effective actions can be taken to protect the public in the event of an accident" (43). There are two types of EPZs: the plume exposure pathway (that area within a 10 mile radius of the plant) and the ingestion exposure pathway (that area within a 50 mile radius of the plant).

Maryland must prepare an REP for each nuclear power plant having any part of its plume exposure pathway within the State. Thus an REP must be prepared for the Peach Bottom Atomic Power Station (Delta, Pennsylvania) as well as Calvert Cliffs. The overall REP for the State (44) and that appendix applying to Calvert Cliffs (45) have been completed; while the appendix for Peach Bottom is still under preparation. BG&E has completed development and testing of the on-site plan for Calvert Cliffs (46) while PECO is nearing completion of the on-site plan for Peach Bottom.

E. Spent Fuel Accumulation

From the spring of 1977 until October 1981 the commercial reprocessing of spent fuel was prohibited in this country.[1] Because of this, spent fuel generated at nuclear power plants across the country is stored on site in spent fuel storage pools. It will be necessary to continue this policy until one of three events occurs:

1) Reprocessing of spent fuel is undertaken, either by the Federal government or within the private sector;
2) Permanent or long-term retrievable storage of spent fuel is made available by the Federal government; or
3) Away from reactor storage becomes available.

It is unrealistic to expect any of the options to exist before the middle to late 1980s at the earliest.

These spent fuel pools were never expected to serve their present function of storing spent fuel for indefinite periods of time. On-site spent fuel pools were designed to hold spent fuel for cool-down for approximately one year pending shipment to a reprocessing facility. Fortunately, the storage of fuel for these unanticipated periods poses no significant environmental threat because fuel elements are at far lower temperatures in the spent fuel pool than they were in the reactor.

The most significant problem associated with on-site spent fuel storage is that the finite capacity of spent fuel pools limits how long utilities can store spent fuel on-site and continue to operate their plants. The current capacities of and amounts of fuel stored in the spent fuel pools at Calvert Cliffs and Peach Bottom are given in Table V-20. Assuming present licensed capacity, and retaining the capacity to discharge one full core, the projected date of the last refueling that can be discharged to the spent fuel pool at Calvert Cliffs is April 1990. Under the same conditions, Peach Bottom has ability to store fuel on-site until 1986 for Unit 2, and 1987 for Unit 3.

Table V-20
Capacity (in Fuel Assemblies) of Spent Fuel Pools at Calvert Cliffs Nuclear Power Plant and Peach Bottom Atomic Power Station, and Amount of Spent Fuel Presently Stored

	Calvert Cliffs	Peach Bottom	
	Both Units	Unit 2	Unit 3
Licensed Capacity	1760	2608	2608
Installed Capacity	1358	2608	2608
Spent Fuel in Storage	584	896	712

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[1]This policy has been reversed by order of President Reagan and commerical reprocessing is now permitted. No group, however, has expressed an interest to undertake reprocessing, given the uncertainty of Federal policy remaining constant through succeeding Administrations.

BG&E is planning an addition to its spent fuel pool which will require relicensing. PECO has the ability to install additional racks, thereby increasing the volume of its spent fuel pool. This change would require relicensing.

F. Radioactive Materials Transportation

Radioactive waste shipments for nuclear power plants in and around Maryland are presented in Tables V-21 and V-22. Since January 1978 there have been 109 and 922 shipments offsite of radioactive waste from Calvert Cliffs and Peach Bottom, respectively. All of those non-spent fuel shipments from Calvert Cliffs and Peach Bottom have been to Barnwell, South Carolina. Three Mile Island also shipped waste to Barnwell prior to the March 28, 1979 accident, but has been prohibited from doing so since then. Shipments of radioactive waste from Three Mile Island now go to Hanford, Washington.

Table V-21

Solid Waste Shipped Offsite for Disposal from the Calvert Cliffs Nuclear Power Plant.

Type of Waste	1978		1979		1980	
	m^3	Ci	m^3	Ci	m^3	Ci
Spent resin, filter sludge, evaporator bottoms, etc.	80.9	1055	41.1	294.5	47.3	504
Dry compressor waste, contaminated equipment, etc.	155.3	59.3	306	53.4	134.3	1.1
Irradiated components, control rods, etc.	367	2.18	84.9	623	69.2	14,268

Table V-22

Solid Waste Shipped Offsite for Disposal from the Peach Bottom Atomic Power Station

1978		1979		1980	
m^3	Ci	m^3	Ci	m^3	Ci
6.91×10^4	4970	8.47×10^4	8030	9.27×10^4	6686

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CHAPTER VI

SOCIO-ECONOMIC IMPACT

The construction and operation of an electric generating station may have significant economic and social impact upon the community where it is located. Among the many possible effects usually considered are changes in:

- population, housing and school enrollment
- land use patterns
- transportation and congestion
- income, employment, and business activity
- local government spending and tax revenues

For convenience, these effects are usually divided into changes affecting the social and economic functions of the private sector and changes affecting tax revenues and the demand for services in the public sector.

The socio-economic effects of power plant construction stem from the rapid increase in population resulting from a sudden increase in the local work force during plant construction. The influx of workers who relocate within the area, as well as commuters, can potentially create demands that exceed the capacity of the public and private services, facilities, markets, and institutions -- the local social and economic infrastructure -- which serve a given community, county, or region. The magnitude of these social and economic effects depends on several factors, particularly the size of the construction project, the size and diversity of the economic base of the local economy, and the infrastructure of the local community. Jurisdictions with a large and well developed economic base are generally more able to meet the service, employment, and economic requirements of major construction projects more readily than jurisdictions lacking this asset.

The most recent major power plant construction project in a rural Maryland community was Calvert Cliffs (completed in 1975). Some preliminary data about the socio-economic effects of this project has been released (1,2) and the results from a more comprehensive study will be available in 1982. These studies showed the need for a means of predicting impacts on the predominantly rural communities which are the proposed sites for future power plants in Maryland. Consequently the Maryland Power Plant Siting Program (PPSP) supported the development of a socio-economic impact assessment model (3). This model, which was subsequently computerized (4), was first applied as part of the Eastern Shore Power Plant Siting Study which evaluated four sites potentially suitable for fossil and nuclear power plant development on the Eastern Shore ot Maryland (5). An estimate of the socio-economic impacts that would result if these sites were developed for power plant use were described in the 1978 Cumulative Environmental Impact Report.

Most recently, this model has been used to estimate the social and economic effects of the expansion of the existing Vienna generating station by Delmarva Power and Light Company (DP&L). DP&L has applied for a Certificate ot Public Convenience and Necessity to construct a 500 MW coal-fired generating unit, Vienna Unit 9. Because the application included the option of constructing capacity of up to 600 MW, social and economic impact studies of the Vienna expansion were based on a 600 MW plant design.

The Vienna analysis provides the most recent data illustrating the potential effects of power plant development within Maryland. The results of this analysis are presented here as an illustration of typical socio-economic effects. This analysis is particularly significant since the Vienna location is typical of the rural Maryland setting where future power plant development is most likely to occur.

A. Employment, Population, Housing and Fiscal Effects

The magnitude of socio-economic effect is determined by a variety of very specific factors, including:

- the size of the plant under construction and its design, both of which influence labor force size
- the location of the plant site with respect to the nearest major cities, which influences the proportion of the work force that commutes rather than becomes immigrant
- the size and economic base of the local communities, which influence the extent to which local municipal and county governments experience increased revenues due to increased local business activity.

The driving force for socio-economic effects is the large labor force necessary for the construction of a modern power plant. It has been estimated that at the peak of construction activity, some 3,200 workers would be involved in the construction of a two-unit, 2,400-MW nuclear power plant (5). At the peak, the work force for a single unit, 600 MW station has been estimated to be approximately 1,000 workers (6).

While construction goes on, these workers purchase goods and services from the local retail economy, increasing local business retail activity. This, in turn, leads to increased wholesale business activity. The result is an increase in local income and employment. It is the sum of these employment gains (direct construction labor plus the additional employment induced by the increase in local business activity) that is the principle driving force for the local effects which occur during the construction phase.

The scale of the effects that these employment changes have on local social and economic conditions depends primarily on two factors: the ability of the local region or county to provide workers from its own population, and the ability of the local community to absorb the new workers who decide to move in during the construction period. These factors are a function of the existing population base and the size and economic integration of the local economy.

Most of the rural counties of the State are located within a relatively short distance (measured in driving time) from the more populous counties and larger metropolitan areas. As a result, even in these rural counties, many of the more severe social and economic effects that may result from large construction projects are mitigated by the relative proximity to large labor force concentrations and urban centers.

Vienna Study

The analysis of the proposed Vienna Unit 9 provides an indication of the scale of the impacts which are likely to result from the construction of what is by current standards a smaller size generating station in a rural, non-suburban Maryland county. In order to understand the impacts of development on a rural economy in Maryland, it is necessary to understand the economic structure of the local community. Because the town of Vienna is located on the border between Dorchester and Wicomico Counties, it is likely that the presence of two urban centers, Cambridge and Salisbury, will serve to buffer adverse impacts because of their relatively well-developed economic base and infrastructure. At the same time, the presence of these cities is likely to improve the ability of the area's economy to obtain maximum benefit from power plant development.

Vienna is almost exactly equidistant from Cambridge (1980 population: 11,703) and Salisbury (1980 population: 16,429) both of which are 16 miles from the town. The town of Hurlock, approximately 10 miles to the north, is the closest moderately sized community (1980 population: 1,690). The Vienna Unit 9 site is immediately north of the existing Delmarva Power and Light Company (DP&L) plant on the north side of the community of Vienna.

Land use and development trends in the vicinity of the Vienna site are typical of many portions of rural Maryland. There have been almost no new homes built within the town of Vienna and its immediate environs during the 1970's. Commercial and industrial development has also been minimal during this period. The market for residential development in the area is quite limited, and the lack of vacant land within the town, problems of failing septic systems, and the reluctance of surrounding property owners (primarily farmers) to develop their property have all contributed to the lack of development (7).

Most of the adverse socio-economic effects of power plant development result from the influx of a large construction work force. These effects are usually largest when the number of workers who move into the local area during the construction period represents a significant proportion of the local population. In the case of the Vienna plant, most workers would be hired from outside of the immediate Dorchester - Wicomico County area because the local labor force does not contain a large enough pool of workers with the appropriate heavy construction skills.

DP&L has provided estimates of the number of workers required to construct and operate the Vienna plant as shown in Table VI-1. The construction of a 600 MW unit at Vienna is estimated to require a maximum of 1,005 workers at the peak of the five year construction period. Of those workers, most are expected to be hired from outside the local economy, only 12.5 percent of the peak work force would come from the Dorchester - Wicomico labor force. Some of these "outside hires" are expected to relocate to the general vicinity of the construction site. Approximately 30 percent of the workers who do relocate are projected to move into Dorchester County.

TABLE VI-1
Workers Required to Construct And Operate Proposed
Vienna Power Plant
1983-1988

Year	Outside Hires	Local Hires	Total Hires
	Construction Period		
1983	57	29	86
1984	468	121	589
1985	879	126	1005
1986	737	98	835
1987	348	96	444
	Operating Period		
1988[1]	30	70	100

[1] First full year following start of plant operations. The number of workers required to operate Vienna 9 is expected to remain constant at the 1988 level during the life of the plant.
Data from Reference 8.

The total number of jobs likely to be generated in the local economy by the Vienna power plant is shown in Table VI-2. Approximately 300 county residents are expected to be employed by DP&L and local employers on or off the construction site during the peak construction year. This effect on employment is likely to be well within the ability of the local economy to absorb. This estimate represents only 2 percent of the employed Dorchester County work force and 20 percent of the total unemployed labor pool in 1977. Although some of these jobs would be filled by workers shifting from their existing occupations to higher paying jobs at the construction site or in the local area, the number of these workers is likely to be too small to adversely affect the labor supply of existing firms.

The workers who gain employment on or off the construction site as a result of the Vienna power plant construction and who relocate into Dorchester County are not expected to have a significant impact on county population, housing demand, or schools. County population at the time of peak construction activity is expected to increase by approximately 150 people, with an increase in school population of approximately 30 students. The total population increase translates to an increase in housing demand of less than 50 units at peak. This additional demand for housing represents only 14 percent of the 350 housing vacancies that are currently projected as the number of units available for rent or sale in 1985 in the absence of

TABLE VI-2

Jobs Generated by Vienna Power Plant in Dorchester County
Direct and Secondary

1983-1988

	At Construction Site				
Year	County Residents	Immigrants[1]	Subtotal	Secondary Jobs[2]	Total
		Construction Period			
1983	13	2	15	24	39
1984	55	21	76	136	212
1985	57	55	112	247	359
1986	44	37	81	112	193
1987	43	13	56	21	77
		Operating Period			
1988[3]	32	9	41	3	44

[1]Number of workers hired from outside the local area who reside in Dorchester County as of the given year. Excludes employees who stay in motels during the week and commute to their homes on weekends.

[2]Filled by county residents.

[3]First full year following start of plant operations. The number of jobs generated by the power plant is expected to decline to 41 by 1990 and then stabilize for the remainder of the operating period.

Data from Reference 6.

power plant construction. Sufficient rental units of all types are projected to be available to meet this demand. The additional demand of 50 units in a county of the size of Dorchester is not expected to have a significant effect on the local housing market other than to reduce the average monthly housing vacancy rate. These effects are summarized in Table VI-3.

The increase in the number of workers during the construction phase will result in an increase in the demand for public services. This increase stems in part from the variety of services, such as police and fire, required by the total increase in work force, including commuters. Most of this increase comes from those workers who move into the county and make use of schools, fire and police protection, water and sewage treatment, social services and general public administrative functions.

In response to this increased demand for services, local governments have several options available. Public officials may choose to maintain services at the existing per capita level, which would require increasing the local government budget in proportion to the population increase. Alternatively, recognizing the short-term nature of the increase, public officials may permit the per capita level of services to decline by not expanding them in proportion to the population change. At the limit, services may not be expanded at all. Because the population increases and increased service requirements that do occur are likely to be relatively small and of short-term duration, local officials have frequently found it unnecessary to greatly expand services and budgets.

Balanced against this demand for services is an increase in revenues. Before the plant comes on line, increased housing prices, new construction of houses, increased local income and business activity will all increase tax revenues. After the plant begins to operate, the county receives revenues from property and capital taxes of the plant.

Table VI-4 summarizes the fiscal effects on several jurisdictions during plant construction and operation. The estimates are based on the assumption that average per capita services are maintained by increased provision of services and represent <u>additional</u> local tax revenues and public expenditures which result from power plant development.

It is seen that throughout the construction period, neither the local municipality of Vienna nor the City of Cambridge (the county seat) are likely to experience significant fiscal effects, and that throughout the period additional tax revenues from construction-related economic activity will more than offset any additional expenditures. Throughout the construction period, Dorchester county government is expected to experience an increase in revenues which exceeds projected increases in expenditures.

Table VI-4 also shows the expected total revenues and total expenditures during the operating period. The net fiscal effect on Vienna and Cambridge during the plant's operating years is expected to be neutral. However, in the case of Dorchester County, the fiscal impact of the operation of Vienna 9 is likely to be substantial, approximately $4.8 million annually in 1978 dollars. That revenue represents approximately 400 percent of the County's Fiscal Year 1981 budget, and is an understatement of the fiscal effect due to the use of 1978 dollar estimates for revenues. These revenues stem largely from the property taxes paid by the utility.

TABLE VI-3

Total Housing Demand Population and School Children
from Proposed Vienna Power Plant Estimated by Year

1983-1988

Year	Immigrating Workers	Housing Demand	Cumulative Population	Additional School Children: Grade School	High School	College	Total
			Construction Period				
1983	2	2	5	1	0	0	1
1984	21	19	58	7	3	1	11
1985	55	48	151	19	8	2	29
1986	37	33	103	13	5	1	20
1987	13	11	35	4	2	0	7
			Operating Period				
1988[1]	9	8	25	3	1	0	5

[1]First full year following start of plant operations. Total housing demand, population and school children during 1989 and the remainder of the operating period are expected to remain constant at 1988 levels.

Data from Reference 6.

In Wicomico County only the city of Salisbury is expected to experience a construction period deficit. That deficit is likely to be very small, and is subsequently offset by small operating surpluses.

Table VI-4
Net Fiscal Impacts for
Plant at Vienna

Jurisdiction	Total During Construction	Yearly Total During Operation
Dorchester Co.	$ 261,600	$4,840,700
Cambridge	15,000	1,700
Vienna	700	500
Wicomico Co.	114,000	27,000
Salisbury	(-6,300)	3,500
State of Maryland	3,320,500	461,500

Data from Reference 6.

Eastern Shore Study

Local fiscal effects of power plant construction are strongly affected by local tax rates. As a result, these effects vary from locality to locality. The variability in these effects can best be illustrated from data prepared for an evaluation of four alternative power plant locations on Maryland's Eastern Shore. These results are summarized in Table VI-5 which show the fiscal effects of the construction of a plant with a peak work force of 3,200 workers.

The variations that exists between counties are the result of differences in the various tax rates and in the extent to which workers move into the county and provide increased tax revenues through increased property values and taxes, increased sales taxes, and business taxes. Dorchester and Wicomico Counties, which experience the largest absolute increase in population, and which also have more extensively developed infrastructures, experience a balanced flow of revenues and expenditures. The other counties and all of the cities (which experience much of the population impacts but less of the revenue benefits because of plant location) experience deficits throughout the construction phase.

As seen in Table VI-5, the county deficits are signficiant, but are manageable in size. In the case of three of the four cities, however, the deficits are of very substantial proportions. Those municipal deficits would require either outside assistance, local tax inreases, or potentially significant reductions in the per capita level of services provided. At both the county and municipal levels, service reductions or tax increases may aggravate the congestion, housing and other difficulties experienced during construction.

Table VI-5

Projected Fiscal Impacts of
2400 MW Power Plant Development,
Various Jurisdictions, Peak Construction Year
and Operating Period[a]

(1977 Dollars)[b]

Jurisdiction	Peak Construction Year Total Revenues	Total Expenditures	Surplus (Deficit)	Deficit as % of Revenues[c]	Operating Period Revenues
Kent County	$735,600	$912,700	$(177,100)	4.0%	$36,000,000
Chestertown	50,100	84,700	(34,600)	13.8%	
Queen Annes	565,200	650,100	(84,900)	1.9%	27,000,000
Centreville	24,500	46,400	(21,900)	21.3%	
Dorchester	1,010,000	982,900	27,100	--	40,000,000
Cambridge	189,800	329,000	(139,200)	13.3%	
Wicomico	1,116,800	1,088,800	28,000	--	28,000,000
Salisbury	113,700	195,800	(82,100)	2.9%	

(a) This study was done for a two unit 2400 MW nuclear plant. No nuclear plant is under consideration for the Eastern Shore. The socio-economic impacts do not depend on the type of plant, therefore the study is representative of any plant requiring the stated labor force.

(b) Rounded to nearest $100.

(c) Deficit shown as percentage of total local revenues, including power plant-induced revenues.

Data from Reference 5.

B. Coal Transportation Effects

DP&L's 600 MW Vienna Unit 9 would use 1.5 million tons of coal a year at an annual capacity factor of 68 percent. On a weekly basis, coal consumption would range between 28,800 and 42,300 tons at 68 and 100 percent capacity factors, respectively. For coal shipped by rail, DP&L expects to rely largely on 100 car unit trains with a capacity of 100 tons of coal per car. On this basis there would be between 2.9 and 4.2 unit trains per week traveling each way to maintain the coal supplies. There would be at least 15,000 coal cars a year traveling over the Delmarva rail system each way. By comparison, approximately 1,000 carloads are expected on the Dorchester segment of the Cambridge to Seaford line in Fiscal Year 1980.

There are two positive effects on the Eastern Shore economy resulting from a decision to transport coal to Vienna by rail: an improvement in rail service due to the upgrading of track conditions in order to serve the heavy loads of coal trains, and long-term assurance that rail operations would be profitable along the applicable branch rail lines. The possibility that rail service might be abandoned would therefore be reduced.

More efficient rail service and reduced travel time between the Eastern Shore and potential markets for local industries could allow rail users to compete in more distant markets and/or improve local profit margins. In addition firms considering the Eastern Shore as a possible location would find the area more attractive with improved rail service. Although the quality of rail service is only one of the many factors a firm would consider in making a locational choice, industries dependent on shipping bulk goods long distances would weigh this factor highly.

If the Vienna site is approved for the power plant and coal is transported by rail, the incentive to maintain rail service on the entire Cambridge to Seaford line would be even stronger than it has been. This could prevent rail abandonment of the Cambridge segment of the line, and could have a significant effect on the Dorchester and Caroline County economies.

In a period of failing local rail service through many areas of Maryland, the impact of improved rail service to present and potential future users can be an important economic benefit from the development of a coal-fired power plant.

There is also a potentially adverse impact of coal shipment by rail: the inconvenience which results from traffic crossings and local noise. Both effects are determined by site-specific conditions.

At Vienna, trains would cross a number of highways at grade at relatively slow speed, causing periodic delays for cars, trucks and other highway users. The amount of delay is dependent on the train speeds, which in turn are controlled by the quality of the track and roadbed. Specific plans for upgrading the Cambridge to Seaford line have not yet been formulated. It appears reasonable to assume, however, that the line would be upgraded to Class II standards, allowing a speed of 25 mph. On that basis, the 100 car unit trains, which would be approximately 5,000 feet long, would take between 2 and 3 minutes to cross an intersection. Warning devices and driver hesitation would increase the delays somewhat, perhaps up to 4 minutes. It is possible that the trains would travel more slowly, particularly through towns such as Hurlock. If the trains travel at only 5 mph, they would take between 11 and 12 minutes to cross an intersection. Adding delay time may increase this period to about 13 minutes.

C. Traffic Congestion Effects

Increased numbers of resident and commuting workers to a power plant site during the construction period frequently produce traffic congestion. The impact on traffic conditions is a function of the increase in the number of commuters and the available carrying capacity of the relevant local transporation routes. Because the severity of traffic congestion is likely to be dictated by local conditions it is not possible to reach a general conclusion about the extent to which traffic congestion during plant construction can be mitigated. With adequate advance planning, severe congestion problems that result from existing bottlenecks can be eliminated by altering highway improvement schedules. Congestion resulting from construction period overcrowding of otherwise adequate roads and bridges may be reduced by adjusting work schedules and traffic flow patterns. The extent to which mitigation measures will succeed in reducing traffic congestion depends on the ability to make the appropriate long-range planning decisions.

Vienna Study

Traffic impacts for the Vienna site were examined in detail for the 1985 peak construction year (6). This analysis revealed that the highway level of service on the two lane segment of U.S. Route 50 in the Vienna area will be unacceptable in 1985 even without the incremental effect of commuting construction workers. The incremental impact of commuting construction workers would increase traffic congestion on this highway segment, particularly for the highway west of the interchange at Route 331. However, plans by the State Highway Administration (SHA) to construct a northern bypass around Vienna to reduce traffic flow through the town will reduce or eliminate this problem.

Traffic impacts at the U. S. Route 50-Route 331 intersection at Vienna were also examined for 1985. This analysis revealed that the incremental traffic resulting from the commuting construction workers would result in an unacceptable level of highway service through this intersection during the summer months. As part of its review of the Vienna plant, SHA proposed highway improvements at the intersection to minimize backups and the potential for intersection related accidents. These improvements are estimated to cost $120,000 in 1980 dollars and would normally be paid for by the utility, and would greatly reduce the projected congestion problems.

Other Studies

The study of four Eastern Shore counties estimated (3) that the increase in the number of commuters coming into the counties ranged from 103 percent (2,524) to 664 percent (3,101). The county receiving the largest increase (relative and absolute) in the number of commuters was the least likely to experience significant traffic congestion because of the capacity of the major roads leading to the area. For each of the other three counties, significant traffic congestion was projected to occur at particular points. Those congestion points were all located at two-lane bridges crossing rivers in the area. In each case, the congestion point had been previously identified by the Maryland Department of Transportation in its long-range plan.

In the case of Calvert Cliffs, a traffic increase of an estimated 1,200 vehicles was experienced during the morning shift. That increase represented 150 percent of the hourly capacity per lane of the major two-lane road used to reach the plant, resulting in significant rush hour congestion (1).

D. Cumulative Local Tax Revenues from Maryland Electric Utilities

Once a power plant comes on line, the local county government receives a significant increase in tax revenue from the utility. The revenues received by local governments once a plant begins to operate provide new flexibility in the options availabe to the locality, including capital improvements, improvement of the local housing stock, expansion of social service activities, and reductions in tax rates. Table VI-5 provided estimates of tax receipts projected for four Eastern Shore counties during the construction and operation of a new power plant. The variation in the tax receipts during the operating period is largely the result of differences in tax rates among the counties. However, in all cases the increase in tax receipts after the plant comes on line is substantial.

Due to very high capital cost of modern base-load units, tax receipts from these facilities tend to be substantial. Tax revenues received from a power plant can dwarf other revenues and expenses in the budget of a rural county. It is not uncommon in such cases for the county to reduce tax rates significantly, which has the effect of reducing power plant tax revenues as well. The rate reductions have occurred in Calvert County as a result of the tax revenues received form the Calvert Cliffs nuclear plant (2).

Table VI-6 gives the revenues received by all Maryland counties from electric utlities and also indicates the size of the revenue increase relative to the county budgets. These tax payments vary substantially, and depend largely on the size, age, and fuel type of the facilities owned by utilities in each county, as well as on local tax rates. The presence of power plants in Anne Arundel, Baltimore, Calvert, Montgomery, and Prince George's Counties and in Baltimore City are evident in the tax receipts of these counties. The impact of a large facility on the budget of a largely rural county is most evident in Calvert County. However, even the presence of an older plant in a rural county has some impact, as may be seen in the cases of Charles and Dorchester Counties.

Table VI-6

Electric Utility Tax Payments to Maryland Counties
Fiscal Year 1980-81

County	BG&E	DP&L	APS/PE	PEPCO	Total	% of County Budgeted Total tax receipts	% of County Operating Budget
Allegany	976		262,597		263,573	1.50	1.18
Anne Arundel	5,110,573		18		5,110,591	3.44	1.75
Baltimore City	18,905,402		2,041		18,907,443	5.83	1.61
Baltimore County	10,291,334		55		10,291,389	3.31	2.52
Calvert	11,089,717		4		11,089,721	49.43	50.62
Caroline	1,120	231,080			232,200	4.89	3.83
Carroll	678,730		82,916		761,646	2.47	1.91
Cecil[a]	46,854	7,331			54,185	.34[a]	.25
Charles	475			3,838,019	3,838,494	15.40	12.10
Dorchester	1,707	585,197			586,904	7.64	5.44
Frederick	68,814		1,163,251	30,127	1,262,192	3.14	2.80
Garrett	151		344,583		344,734	3.43	3.07
Harford[a]	1,773,674		3		1,773,677	3.72	2.61
Howard	1,515,004		10,286		1,525,290	2.50	1.72
Kent	1,013	163,180	23		164,216	3.34	2.45
Montgomery	102,795		351,223	10,055,283	10,509,301	2.77	1.59
Prince George's	891,161		57	12,301,680	13,192,898	5.35	2.79
Queen Anne's	1,674	196,176			197,850	2.61	2.20
St. Mary's	553			168,704	169,257	1.18	.81
Somerset	744	121,934			122,678	3.49	2.29
Talbot	3,982	59,649			63,541	.89	.55
Washington	2,973		685,356		688,329	2.21	1.90
Wicomico	1,752	377,696			379,448	2.33	1.40
Worcester	968	246,613			247,581	2.01	1.49
TOTAL	50,492,056	1,988,856	2,902,413	26,393,813	81,777,138		

(a) Also receives taxes from Conowingo Power Co., (not included).

Data from Reference 9.

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CHAPTER VII

NOISE IMPACT

An evaluation of the impact of a power plant includes an evaluation of noise (1). This evaluation will typically consist of the following steps:

- Identification of the noise sources of the facility and a description of the nature of the emissions,
- Analysis of noise propagation to off-site areas,
- Evaluation of already existing noise (ambient noise) in off-site areas,
- Evaluation of the effects of the intruding noise on people,
- Consideration of constraints and mitigation if necessary.

Noise can be described either by spectrum components or overall energy levels. The more complete description is by spectrum components in which sound energy is quantified at different frequencies. This is an important method of characterizing sound since the human ear has a sensitivity which varies markedly with frequency. Propagation characteristics are also frequency dependent. Typically, a spectrum description will use nine separate octave bands,[1] centered at intervals between 31 and 8000 Hz. The sound energy is reported in decibels (dB).[2]

The individual octave bands are weighted according to the frequency sensitivity of the human ear. An overall sound level, described as the "A-weighted sound pressure level", reported in units of dBA can be obtained. Table VII-1 lists several common sources of noise in terms of their overall dBA levels.

Since many noise sources fluctuate over time, statistical descriptions of the A-weighted sound can be defined. The following descriptors are frequently used:

L_{eq} (equivalent sound level), is the A-weighted sound pressure level averaged over a 24-hour period,

L_{dn} (day/night sound level), is the dBA sound level averaged over a 24-hour period, but where the noise levels between the hours from 10 PM to 7 AM are treated as if they were 10 dB greater than the actual level,

----

[1]An octave is a doubling of frequency. An octave band analyzer will add up all the energy that exists in a particular band of frequencies that is one octave wide.

[2]A decibel description of sound energy needs to state a unit of reference. For acoustics, as applied to noise and human hearing, the reference (zero dB) is approximately the quietest sound a person with good hearing can hear (20 $\mu N/m^2$). The decibel is a logarithmic unit, an increase of 3 dB corresponds to a doubling of the energy level.

TABLE VII-1.
Typical A-Weighted Sound Levels Measured with a Sound-Level Meter

	DECIBELS	
	140	
50 HP Siren (100')		
	130	
Jet Takeoff (200')		
	120	
Riveting machine	**110**	
	100	
Textile Weaving Plant Subway Train (20')		
	90	Boiler Room
Pneumatic Drill (50')		
	80	Inside Sport Car (50 MPH)
Freight Train (100') Vacuum Cleaner (10') Speech (1')	**70**	
		Near Freeway (Auto Traffic)
	60	Large Store
Large Transformer (200')		Private Business Office
	50	
		Average Residence
	40	Nightime Residential areas
Soft whisper (5')		
	30	
	20	
	10	
Threshold Of Hearing	**0**	

Note: These values are taken from the literature. Sound-level measurements give only part of the information usually necessary to handle noise problems, and are often supplemented by analysis of the noise spectra.

L_{10}, L_{50}, L_{90} are dBA sound levels that are exceeded for 10, 50, and 90 percent of the time, respectively.

A. Noise Sources

Major power plant noise sources can usually be categorized as follows:

- The primary generating facility, consisting of turbines, generators, and associated equipment,
- Cooling towers (natural or mechanical draft),
- Coal handling machinery, consisting of bulldozers, conveyors, and crushers,
- Large vehicles (trucks and trains).

The first category, the primary generating facility, contains a multitude of individual noise sources, such as fans, furnaces, turbines, generators, outdoor paging systems, etc.

Cooling towers can also be a significant source of noise from a power plant. Natural draft cooling tower noise is produced by the sound of falling water, a mechanical draft tower generate additional fan noise. Fan noise generally dominates the noise spectrum for frequencies below 2000 Hz, while water noise dominate above. Table VII-2 lists octave band and dBA levels for noise measured at various points surrounding several plants. Five plants are listed ranging from a small diesel plant (48 MW) to a large nuclear plant (1645 MW). The lowest noise emissions was from the nuclear facility. The small diesel plant produced noise levels comparable to the largest coal-fired plant. The noise from such a small plant, when propagated to neighboring areas, can actually be more significant than that from a larger facility, because of the relatively small land area often allocated to a small facility.

In addition to the broad band noise sources discussed above, discrete tones must also be considered. A discrete tone results from concentration of sound energy into a narrow band of frequencies. For a given amount of energy, a discrete tone is more noticeable than broadband noise. Because a relatively small addition of energy in the form of a discrete tone can increase the annoyance value of a noise, noise regulations often require a 5 dB lower noise level if prominent discrete tones are contained in the intruding noise.

Noise emissions from most power plants do contain discrete tones, usually related to the rotation rates of large generating machinery. However, with one exception, past studies did not find discrete tones strong enough to increase the annoyance potential of the noise emissions.

Table VII-2

Octave-Band Noise Under Full Load at 1000 Feet from Plant Edge.[a] Plants Under Full Load

Band Center (Hz)	Coal-Fired PLANT I (550 MWe)	Coal-Fired PLANT II (550 MWe)	Coal-Fired PLANT III (1,500 MWe)	Nuclear PLANT IV - (1,645 MWe)			Diesel PLANT V- (48MWe)		
				Front	Sides	Back	Front	Sides	Back
31	64.1	60.1	70.9	55.7	52.7	59.7	68.0	67.0	73.0
62	62.1	58.1	69.9	54.7	53.7	59.7	59.0	65.0	68.0
125	57.1	57.2	68.0	52.8	50.8	59.8	56.9	63.9	67.0
250	53.2	49.2	59.1	47.8	45.8	50.8	54.9	56.9	59.9
500	52.4	48.5	56.3	42.0	39.0	47.0	50.6	52.7	54.7
1K	46.8	43.0	53.7	39.5	33.5	41.5	45.1	55.1	56.1
2K	38.9	35.5	52.3	32.8	29.8	39.8	40.6	51.6	48.6
4K	24.8	27.3	52.0	22.2	17.2	30.2	32.9	43.9	41.9
8K	2.1	17.7	40.0	12.5	-1.5	18.3	18.4	26.4	25.4
dBA	52.7	49.3	60.7	45.2	42.1	49.7	52.4	58.9	59.7

[a] Values in dB with reference to 20 $\mu N/m^2$

B. Noise Propagation

Calculations are required to determine the noise levels that will be propagated from a noise source to off-site areas. In this process, it is necessary to consider the following points:

- geometric spreading (the dilution of sound energy as it propagates away from a source);
- atmospheric absorption (the loss of sound energy as it is converted into heat in the air);
- absorption by vegetation (usually trees);
- obstruction by barriers (terrain or buildings which block the line-of-sight path between the source and listener).

The overall noise is the sum of the noise energy propagated from each source to a given point.[1]

These calculations must be performed for numerous points surrounding the plant. The results can be summarized in terms of dBA contours, i.e., the line which connects points which have equal dBA levels. Figures VII-1 and VII-2 show examples of dBA contours for two typical facilities. Figure VII-1 refers to a coal burning facility consisting of an existing 550 MW plant and two proposed 850 MW units. Figure VII-2 applies to a diesel generating facility consisting of eight units, each of 6 MW capacity. The effect of shielding by trees is included. As mentioned earlier, the small diesel facility propagates considerably more noise beyond the plant site boundaries than the large coal-fired facility.

C. Effects of Noise on People

Several indices may be examined to determine how people will be affected by intruding noise. One such method correlates noise levels to various social/physiological functions; i.e.,

- actions taken by citizens, such as formal complaints or lawsuits,
- people's responses on social survey questionaires,
- interference with understanding of speech,
- interference with sleep.

Figure VII-3 shows an example of an evaluation procedure documented by the U.S. Environmental Protection Agency (EPA) in which the intruding noise is correlated with observed community actions. Table VII-3 shows a number of correction factors in the EPA method which account for conditions that could make a given problem more or less sensitive compared with a base-case. In

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[1]It is not correct to add dBA levels arithmetically when computing the combined noise from several sources. For example, two sources each at 50 dBA would have a combined level of 53 dBA.

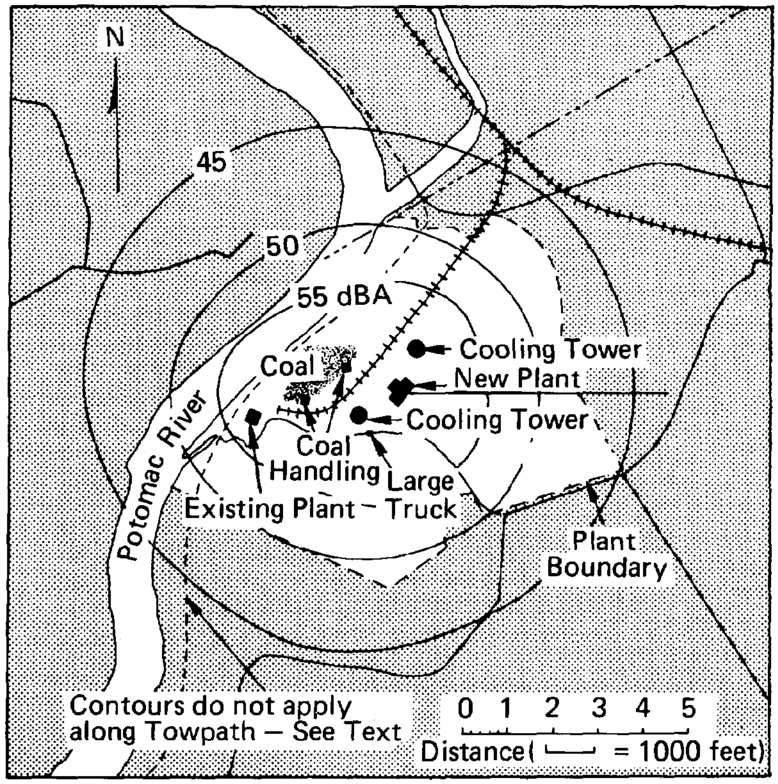

Fig. VII-1 Noise Contours Calculated for Coal Burning Plant

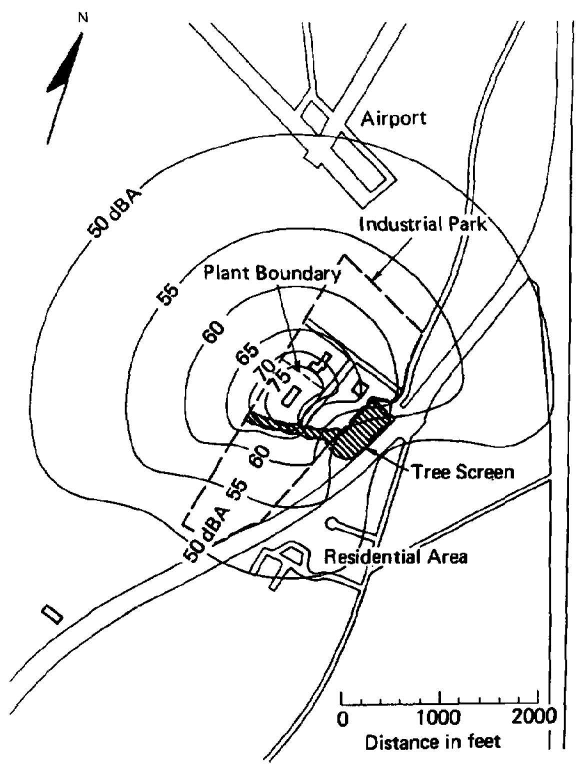

Fig. VII-2 Noise Contours Calculated for Diesel Plant

Table VII-3
Corrections to be Added to the Measured Day-Night Sound Level (L_{dn}) of Intruding Noise to Obtain Normalized (L_{dn})
(As recommended by Enviromental Protection Agency)

Type of Correction	Description	Amount of Correction to be Added to Measured L_{dn} in dB
Seasonal Correction	Summer (or year-round operation)	0
	Winter only (or windows always closed)	-5
Correction for Outdoor Noise Level Measured in Absence of Intruding Noise	Quiet suburban or rural community (remote from large cities and from industrial activity and trucking)	+10
	Normal suburban community (not located near industrial activity)	+5
	Urban residential community (not immediately adjacent to heavily traveled roads and industrial areas)	0
	Noisy urban residential community (near relatively busy roads or industrial areas)	-5
	Very noisy urban residential community	-10
Correction for Previous Exposure and Community Attitudes	No prior experience with the intruding noise	+5
	Community has had some previous exposure to intruding noise but little effort is being made to control the noise. This correction may also be applied in a situation where the community has not been exposed to the noise previously, but the people are aware that bona-fide efforts are being made to control the noise.	0
	Community has had considerable previous exposure to the intruding noise and the noise maker's relations with the community are good	-5
	Community aware that operation causing noise is very necessary and it will not continue indefinitely. This correction can be applied for an operation of limited duration and under emergency circumstances.	-10
Pure Tone or Impulse	No pure tone or impulsive character	0
	Pure tone or impulsive character present	+5

Figure VII-3, the assumptions are that the plant noise is continuous, the surrounding community is of a quiet suburban or rural type with some prior exposure to the intruding noise, windows of residences are assumed to be partially open, and the noise does not contain prominent discrete tones.

D. State Noise Regulations

The State of Maryland has noise regulations which restrict the noise levels that a person may cause or permit. As shown in Table VII-4, the State noise constraints are categorized by zoning district and time of day. Daytime hours are 7 AM to 10 PM, and nighttime hours 10 PM to 7 AM. Allowable discrete tones are 5 dBA lower than the levels listed in the table.

Construction noise is exempt from the regulations of Table VII-4, Also exempt are railroad noises associated with train passbys, as well as auditory warning devices. State noise regulations concerning construction noise are as follows:

> A person may not cause or permit levels emanating from construction or demolition site activities which exceeds:
>
> a) 90 dBA during daytime hours
>
> b) the levels specified in Table VII-4 during night-time hours.

E. Site Evaluations

Noise evaluations completed on six power facilities are briefly described here.

Brandon Shores

A coal-fired plant of 1240 MW capacity is planned to be added adjacent to an existing facility known as Wagner. The Public Service Commission (PSC) imposed a constraint of 45 dBA in areas zoned for residential use in order to protect against annoyance. Subsequenly, the utility filed for a revised restriction to 50 dBA at night, and 60 dBA during the day. Additionally, the utility has requested that the noise criteria should apply to the emissions from the new facility only, rather than the total noise from the combined facility. These issues remain unresolved at this time.

Dickerson

An 850 MW coal-fired plant is planned to be added to an existing 550 MW facility. Since the site was situated in a rural/suburban community, noise was an important consideration. Potential disturbances along a U. S. Park Service hiking path was questioned by intervenors. In order to protect against annoyance, the PSC imposed a 45 dBA noise limit, as well as individual octave band constraints. The utility petitioned to have a relaxation of the octave-band constraints. It was subsequently recommended that

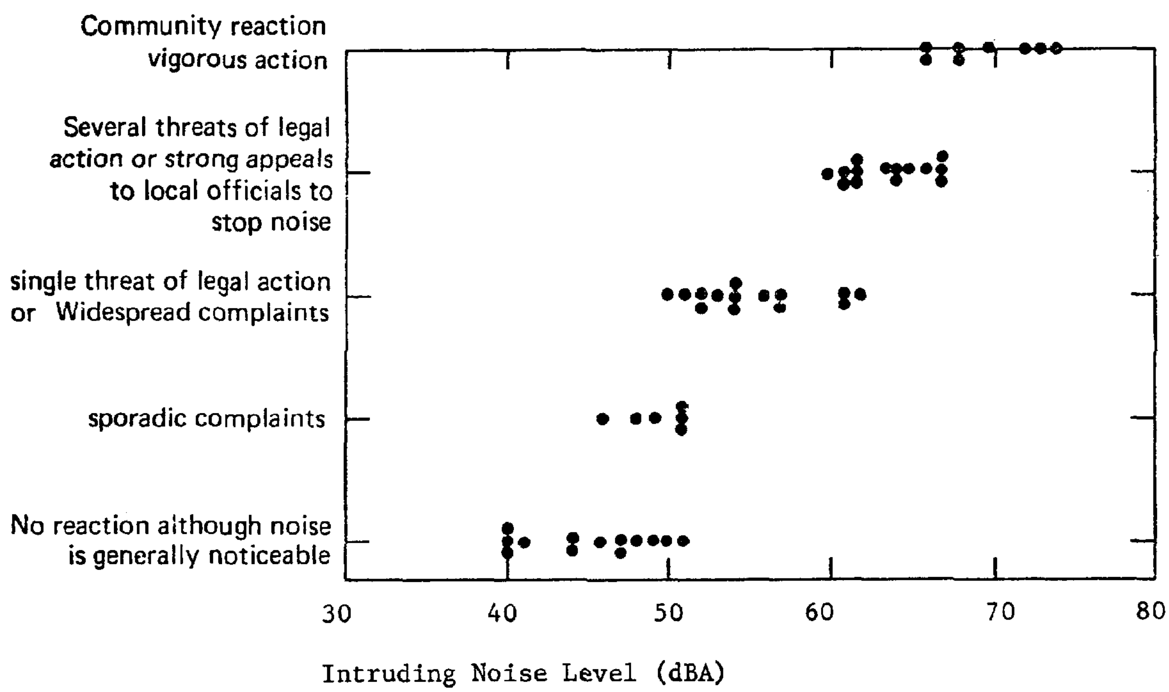

Fig. VII-3. An example of community reactions to plant noise levels. Graph applies to a quiet suburban or rural community, with some prior exposure to the intruding noise. Windows of residences are assumed to be parially open, and intruding noise is continuously present.

Table VII-4

State Noise Regulation

	Maximum Allowable Noise Levels by Zoning Category (dBA)		
	Industrial	Commercial	Residential
Day	75	67	60
Night	75	62	50

the octave band constraints could be relaxed in certain respects without serious additional annoyance.

Douglas Point Site

A nuclear facility of 2356 MW capacity was planned in a quiet rural area along the lower Potomac River. The evaluation revealed that noise would not be a significant source of annoyance. The application has, however, been withdrawn.

Easton

A 48 MW diesel facility is planned adjacent to the community. Due to the small land area and relatively large noise emissions, the PPSP study judged that noise might create annoyance in residential areas if current construction practices were followed. The PSC has ordered the utility to submit a constuction plan that included provisions for noise abatement.

Sollers Point

A gas turbine facility was planned to be added to a facility which already contained several other gas-turbine peaking units. Due to the design and placement of the proposed addition it was judged to be a potential source of annoyance if conventional design practices were followed. The utility agreed to accept design constraints which would allow the unit to be operated without causing annoyance. The utility has since decided not to implement this expansion.

Vienna

A 500 MW coal-fired unit is planned by Delmarva Power and Light for the Eastern Shore of Maryland. The site location favored by the utility would place this unit at a facility already containing several smaller units. A re-routing of a major highway around the plant was also being planned by the State Highway Administration. With the new route, ambient noise levels in the town of Vienna would drop significantly, and plant noise could cause annoyance if proposed design practices were followed. In addition, for certain conditions of operation, it was concluded that State noise regulations would be exceeded by a few dBA. At the present time, PSC hearings have not been concluded.

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3. J.P. Reilly, "Potential Impact on Community Noise Levels", Chapter 6 of "Addendum to Power Plant Site Evaluation, Dickerson Site", The Johns Hopkins University Applied Physics Laboratory, Report Number 3-1, January 1974.

4. J.P. Reilly, "Noise Impact", Chapter 9 of "Power Plant Site Evaluation Report - Douglas Point", The Johns Hopkins University Applied Physics Laboratory, Report Number PPSE 4-1, Vol 2, May 1974.

5. J.P. Reilly, "Noise Impact", Chapter 4 of "Power Plant Site Evaluation Final Report - Easton Utilities Commission Plant No. 2", The Johns Hopkins University Applied Physics Laboratory, Report Number PPSE 5-2, March 1975.

6. J.P. Reilly, "Power Plant Noise Models for Community Impact Studies", <u>Proc. of the Technical Program, NOISEXPO 75</u>, Atlanta, GA, April 30-May 2, 1975.

7. M. Cwiklewski, "Models for the Prediction of Traffic Noise". The Johns Hopkins University Applied Physics Laboratory, Report CPE-76-067, June 7, 1976.

8. M. Cwiklewski, "Present and Projected Neighborhood Ambient Noise Levels in the Sollers Point Area", Johns Hopkins University Applied Physics Laboratory, Report Number CPE-76-100, August 18, 1976.

9. M. Cwiklewski, "Noise Impact of the Four Gas Turbine Electrical Generating UnitsProposed for BG&E Sollers Point Facility", The Johns Hopkins University Applied Physics Laboratory Report CPE-76-077, June 24, 1976.

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CHAPTER VIII

GROUNDWATER IMPACT

In addition to condenser cooling water, power plants also need freshwater for boiler make-up, pump cooling, sanitary water supply, and pollution control equipment. A diagram showing typical uses is shown in Figure VIII-1. These uses can be considerable - up to 1.6 million gallons of water daily for 2,000 MW of fossil-fuel capacity and 500,000 gallons daily for a 2,000 MW nuclear plant. Much of this water demand comes from the requirement for extremely clean (demineralized) water in modern high pressure super-critical boilers, thus leading to the requirement of multiple filtration and backwash systems and limited reuse (1). This water can be drawn from four sources, depending on location of the plant.

- Non-tidal river - Usually, the water is withdrawn from the river and purified for use. Examples of plants using this type of withdrawal are Dickerson and R.P. Smith.

- Industrial water supply - Large cities like Baltimore and Washington provide water of industrial quality to power plants and other large users.

- Groundwater/Desalination - For plants located near brackish surface water, but remote from municipal supplies, there are two alternatives: to desalinate the surface water or to use groundwater. For four of the Maryland plants (Morgantown, Chalk Point, Calvert Cliffs, and Vienna), the choice has been to use groundwater. The potential impact of these wells on adjacent users is discussed below.

The potential impact of the use of groundwater lies both in a reduction of the quantity of water available, and in a decrease in the hydraulic head or "potentiometric surface" in the area surrounding the point of withdrawl. This surface represents the level to which the water would rise if a well were drilled into the aquifer in question. As the well is pumped, a "cone of depression" centered around the well is created in this surface. If pumpage lowers the surface below the intake level of the pump of a neighboring well in the same aquifer, then that well becomes "dry". In such a case, the pump would have to be lowered to a depth that would remain below future lowerings of the potentiometric surface.

The Calvert Cliffs plant has 3 wells averaging 620 feet in depth that withdraw water from the Aquia aquifer. The average monthly usage (Figure VIII-2) is far below the allowed average and maximum appropriations of 600,000 gpd and 865,00 gpd, respectively. Water levels showed an initial decline of about 10 feet, but observations taken since that time show no further lowering. PPSP, through the U.S. Geological Survey, is instrumenting a permanent observation well at this site.

The Morgantown plant has 5 wells, averaging 1,100 feet in depth, that withdraw water from the Patuxent aquifer. The average withdrawal (Figure VIII-3) is eight hundred thousand gallons daily. Water levels of the

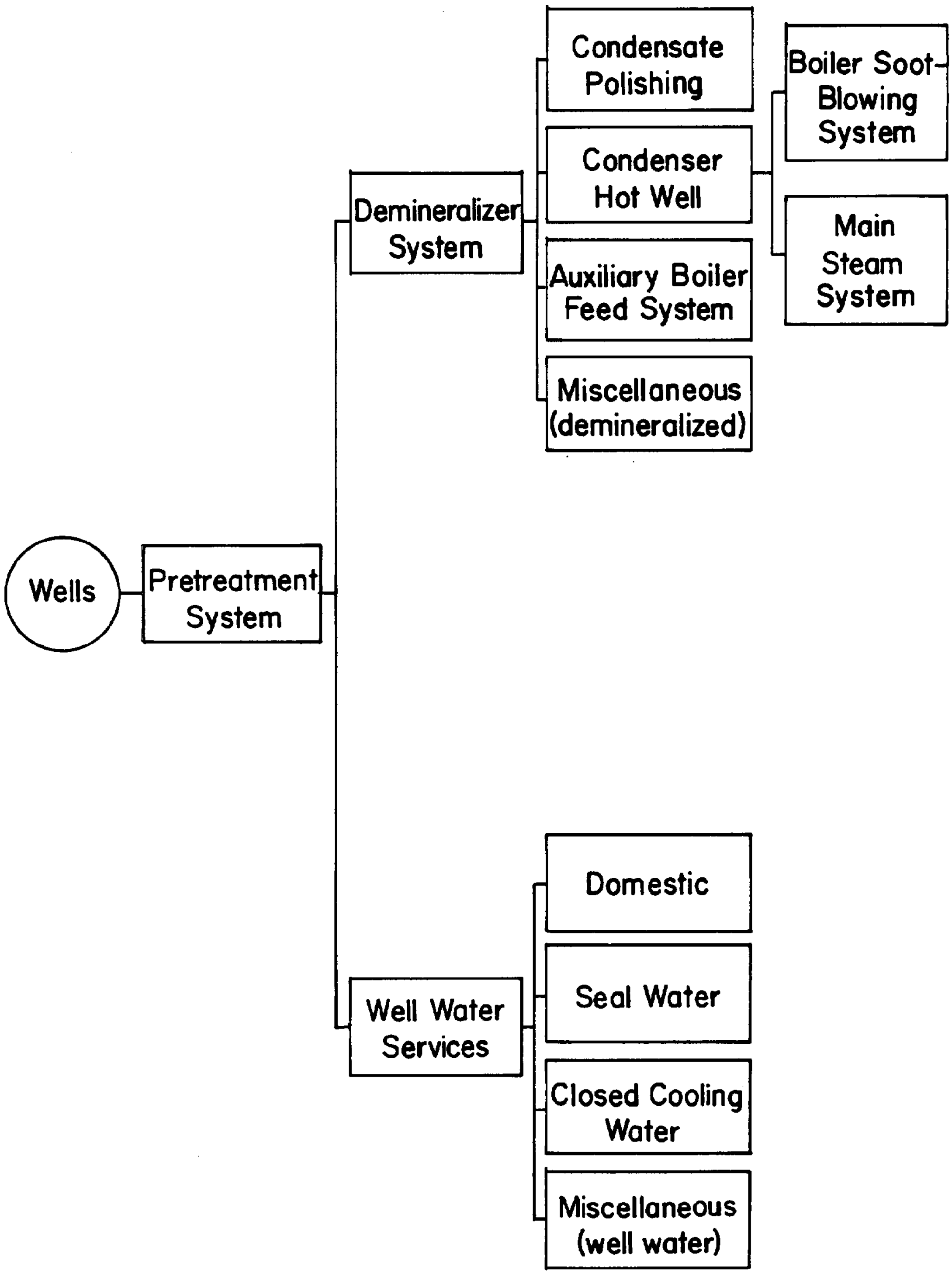

Figure VIII-1. Typical freshwater uses for a fossil-fueled power plant.

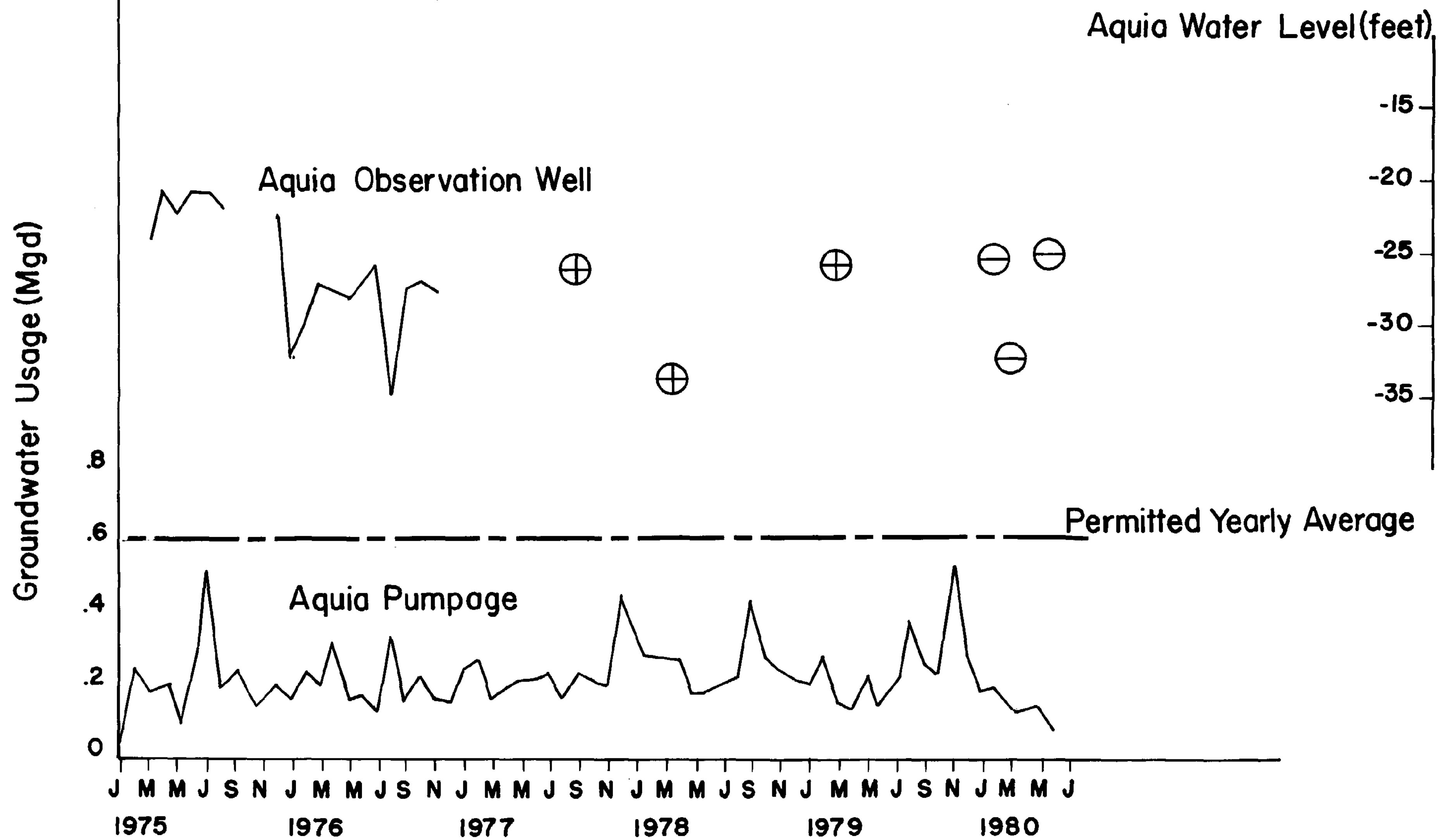

Fig. VIII-2. Pumpage and water levels of the Aquia Aquifer at the Calvert Cliffs Nuclear Plant. The circled readings represent point measurements rather than monthly averages.

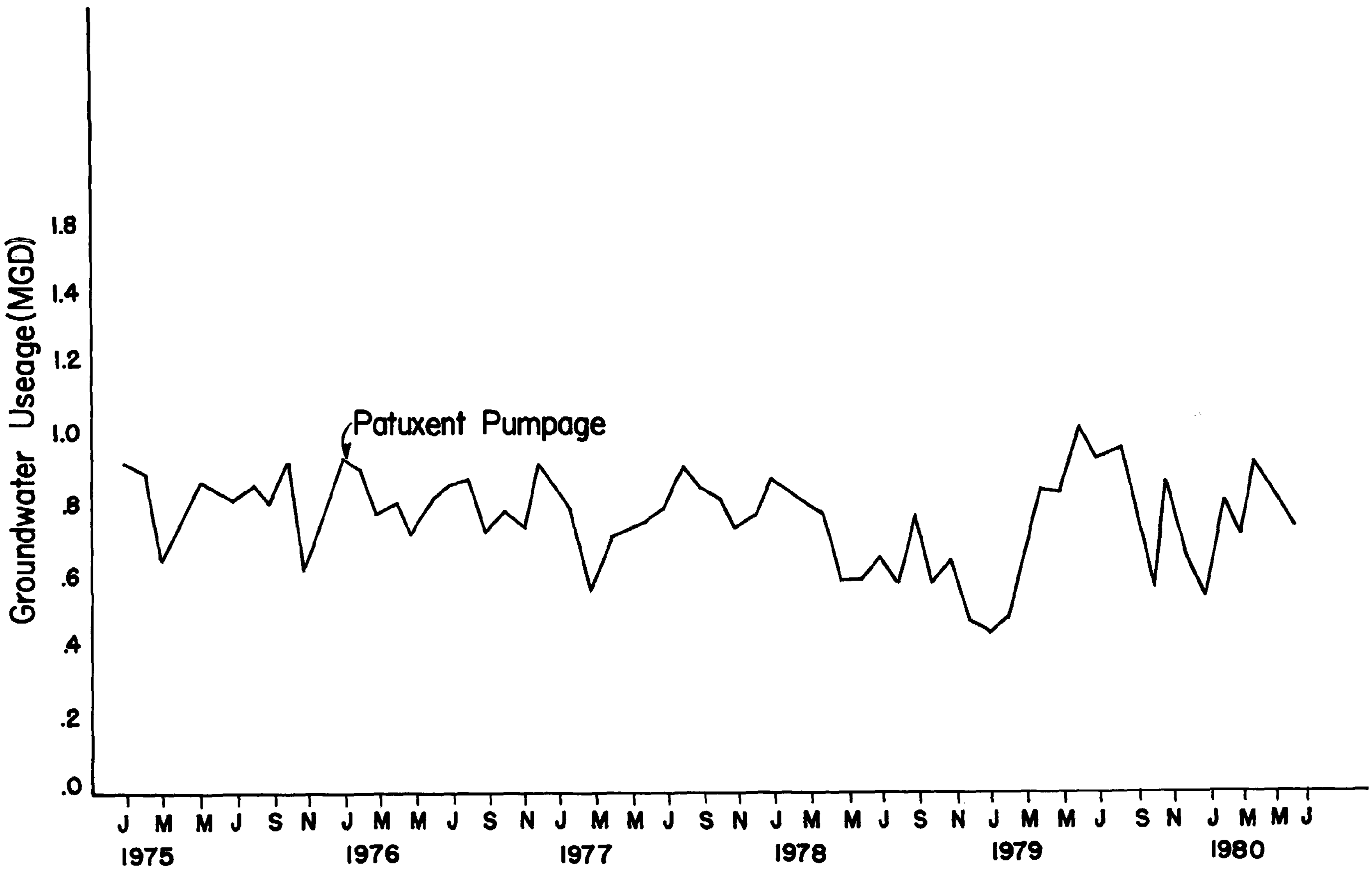

Fig. VIII-3. Pumpage from the Patuxent aquifer at the Morgantown Power Plant.

Patuxent aquifer have declined 90 - 100 feet since plant operation began in 1971, as measured by an observation well near the plant (2). Water levels of the upper aquifers have declined at rates basically unchanged since before PEPCO began pumping, indicating that the plant is not directly linked to the decline (2). At the request of the Power Plant Siting Program, the U.S. Geological Survey has installed a continuous water-level recorder on an observation well screened in the Patuxent aquifer at this site.

Vienna presently draws from 5 wells, four are screened in an unconfined aquifer (Pleistocene) (35 - 54 feet) and one draws from the Nanticoke aquifer (310 feet) (3). The average withdrawal rate for both aquifers is shown in Figure VIII-4. With the retirement of Units 5-7, useage is expected to decline until start-up of Unit 9 in 1988. The expected yearly average withdrawal from Unit 9 is 0.39 mgd (4). Because of the high yield of this aquifer, no water supply problems are anticipated for the area (5).

The Chalk Point plant draws from two aquifers, the Patapsco (1,066 feet) and the Magothy (630 feet). The average withdrawals, shown in Figure VIII-5, indicate that the plant exceeded the maximum monthly average of 1 mgd for the Magothy aquifer twice since 1979. The water level (shown in Figure VIII-5) in the Magothy has consistently decreased since operations began in 1963, reaching a level of -55 feet during 1979-80. The plant does not pump from the upper aquifer (Aquia) used for domestic wells in the area. There are no other users of the Magothy in the immediate vicinity of the plant (< 8 miles). Plant influence can be put in perspective by looking at the effect of these withdrawals on the potentiometric surface in the area. Figures VIII-6 and VIII-7, surveys (USGS) of the Magothy surface taken during early September 1979, and August 1980, shows a "cone of depression" near the plant. Similar cones exist near Waldorf (as shown on map), Annapolis, and Severna Park.

Comparison of the September, 1977 map in the 1978 CEIR (6) to the August, 1980 map indicates that changes have taken place. This comparison is accomplished in Figure VIII-8, a difference map of the two potentiometric surfaces. In the Northern section of the aquifer, levels have risen or remained fairly constant. However, the Chalk Point/Waldorf areas show large declines reflecting increased pumping rates and drawdown. These declines are large enough that users who can not adjust their pumps with water level ("telescopic wells") may be affected. The demand for water in the La Plata/Waldorf and Chalk Point areas is expected to increase within the next few years (7). In particular, the power plant has an additional unit scheduled for completion in 1982. To meet this demand, PEPCO has indicated that they will drill at least one more deep well into the Patapsco Aquifer (8). Since an adequate supply of water is available from this level, the power plant operation should not affect the areas water supply. Also, a PPSP-sponsored study of water use at this site may indicate cost-effective methods of reduced consumption (9).

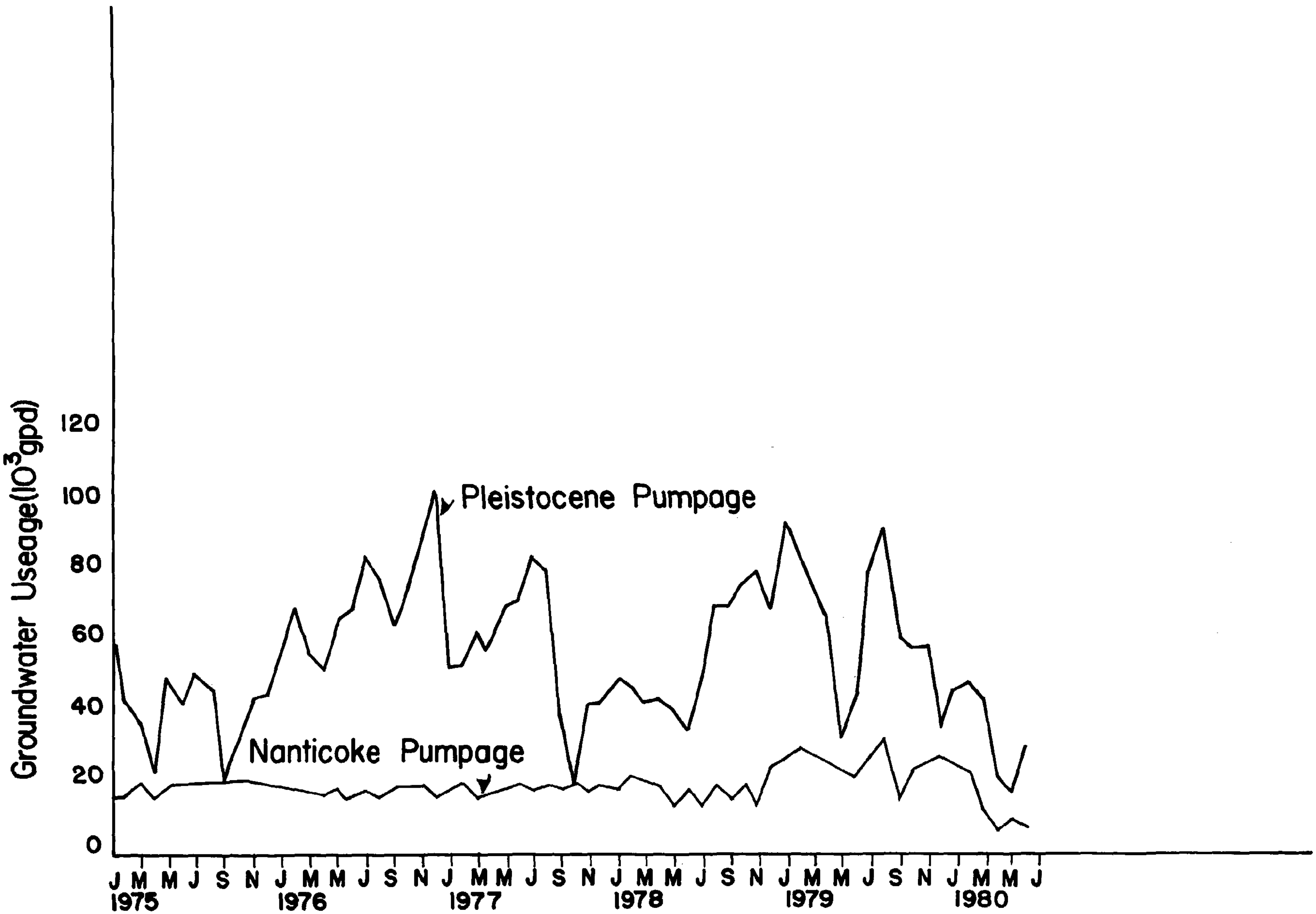

Fig. VIII-4. Pumpage from the Pleistocene and Nanticoke aquifers at the Vienna Power Plant.

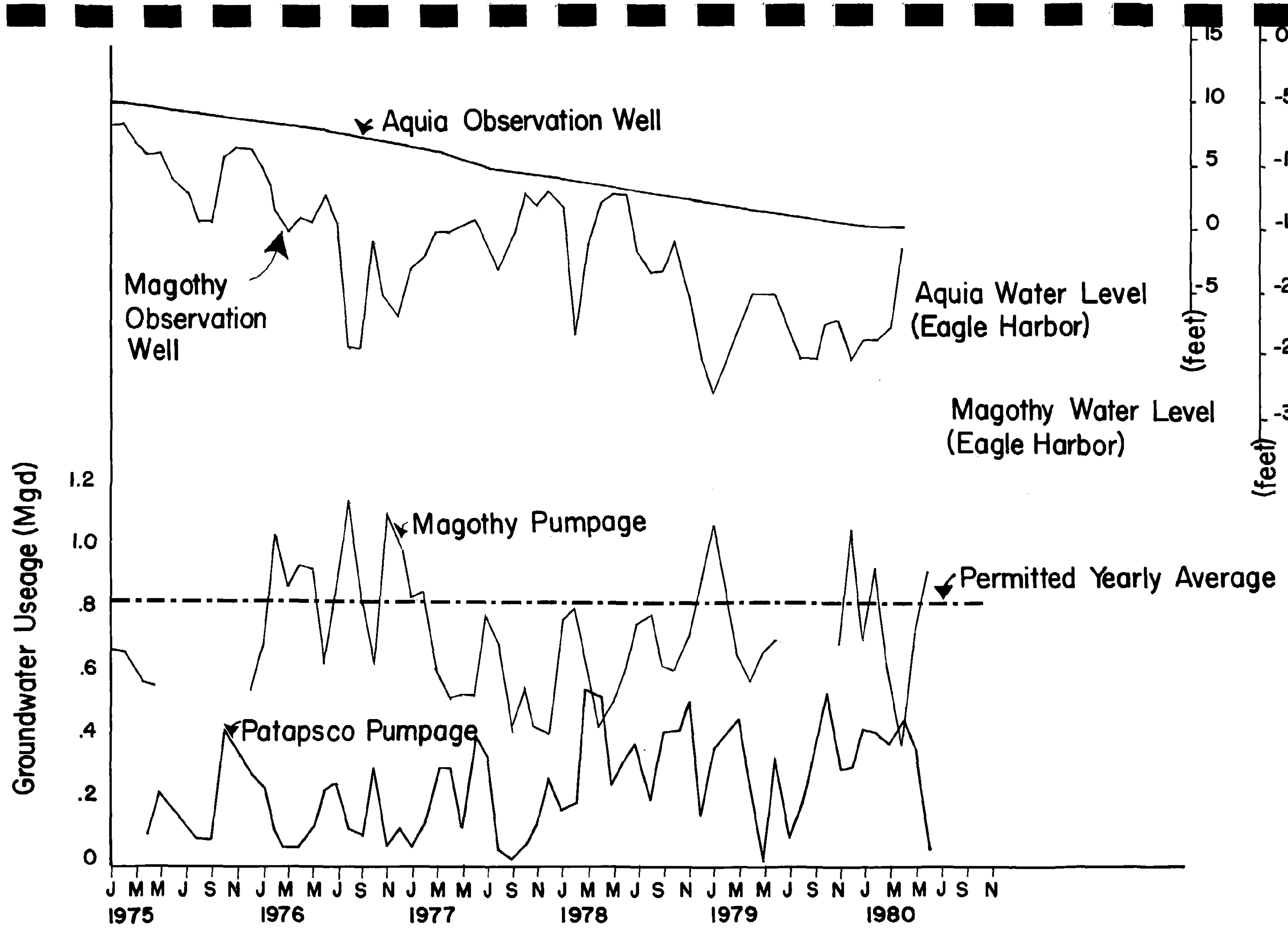

Fig. VIII-5. Pumpage from the Magothy and Patapsco aquifers at Chalk Point. Also included are water levels at test wells in Eagle Harbor, approximately 2 miles north of the plant.

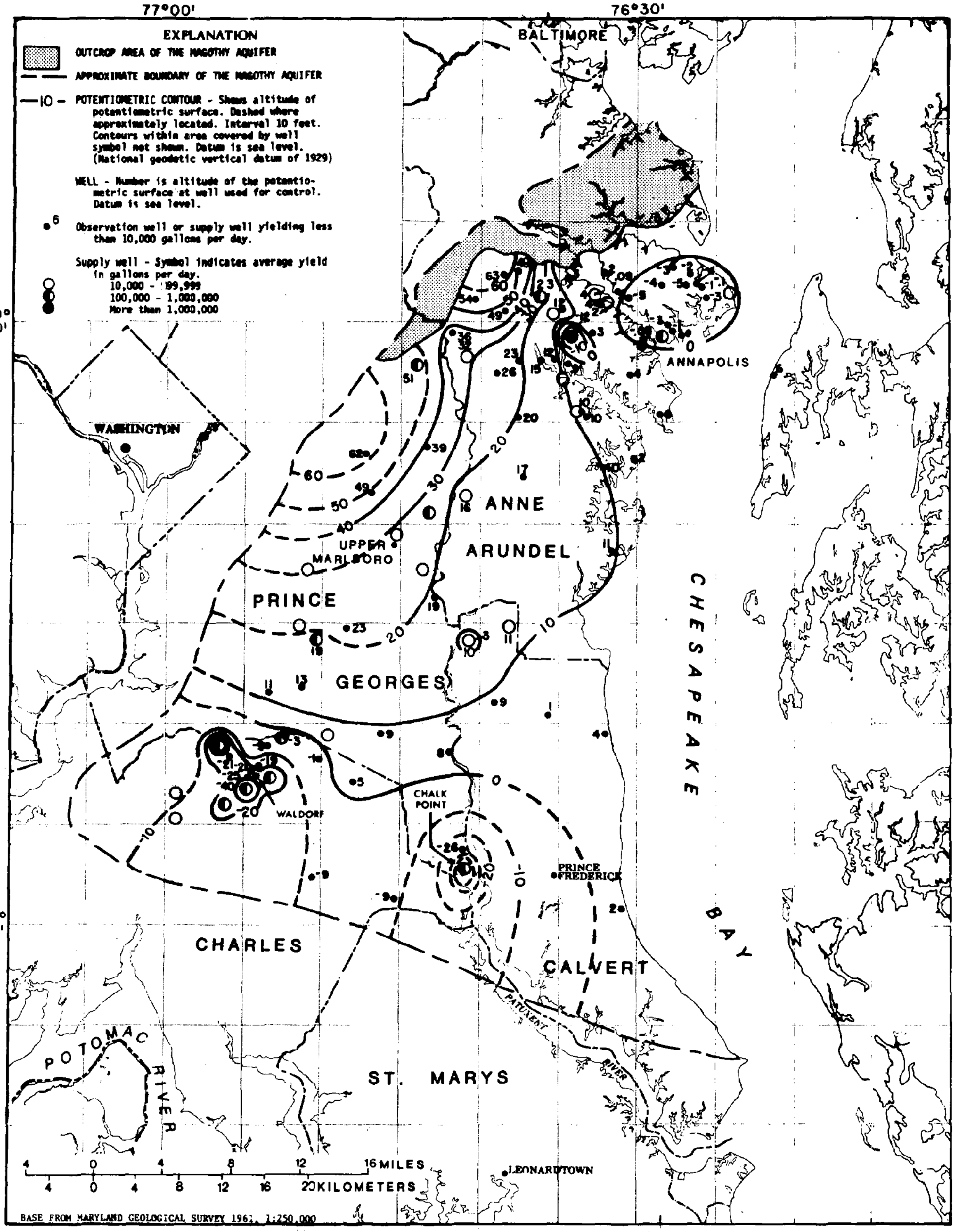

Fig. VIII-6. Map showing the potentiometric surface of the Magothy aquifer in southern Maryland. September, 1979.

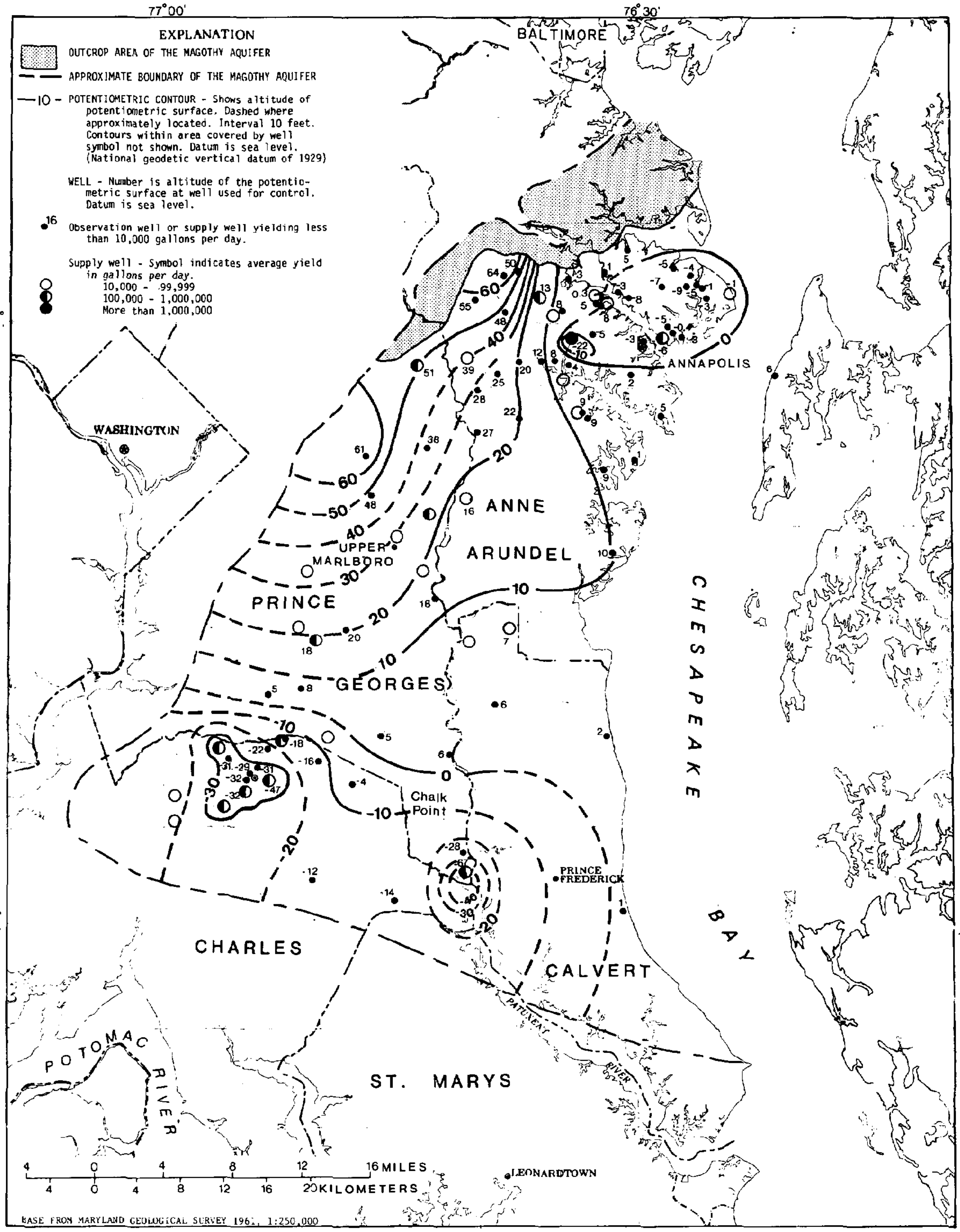

Fig. VIII-7. Map showing the potentionmetric surface of the Magothy aquifer in southern Maryland. August, 1980.

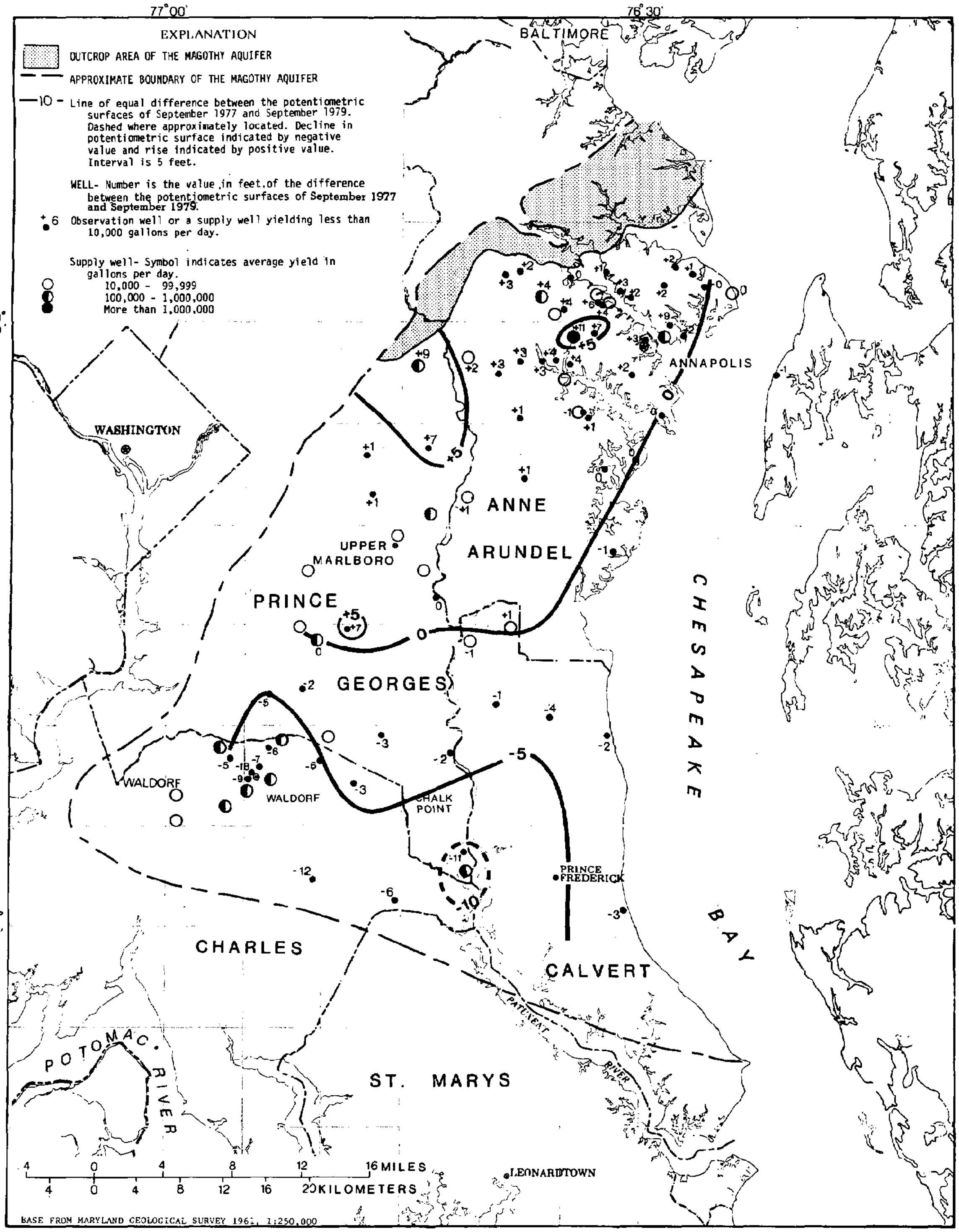

Fig. VIII-8. Map showing the difference in the potentiometric surface of the Magothy aquifer from September, 1977 to August, 1980.

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CHAPTER IX

SOLID WASTE MANAGEMENT

Burning of coal produces combustion gases that contain solid flyash and gaseous sulfur oxides. When these products are cleaned from the stack gas by the use of precipitators and scrubbers, large volumes of flyash and sludge are generated. Lesser quantities of bottom ash and boiler slag are also produced. Broadly speaking, such wastes must either be used, stored temporarily, or permanently disposed of. Engineering costs and environmental hazards may be associated with any of these approaches.

Where possible, waste product utilization is desirable. Bottom ash is frequently used as a road base, as a drainage blanket, and as an aggregate in concrete. Federal law requires the use of flyash in cement in federal projects, where feasible, and Maryland law requires that flyash be stored in a manner permitting its subsequent recovery and use (1). The principal potential uses of flyash take advantage of its hardening properties in the mixing of concrete; in structural fill; and in admixture with other wastes to simplify their disposal and minimize leachate generation. Calcium sulfate scrubber sludge, or "abatement gypsum", from non-recoverable processes can sometimes be used as a soil conditioner, in wallboard manufacture, or as a set-retarding agent in concrete. Elemental sulfur or sulfuric acid is obtained from recoverable sulfur removal processes.

At present some flyash is being sold for re-use and the remainder is being placed in managed landfills. Previously, ash was placed wet in unlined disposal ponds or deposited on marshland. Such disposal is no longer likely to meet land use and environmental regulations in most areas of Maryland. No scrubber sludge will be generated in Maryland until a scrubber begins operation in 1988 at the Vienna plant of Delmarva Power and Light (DPL).

Quantities of waste requiring disposal will probably increase in response to increased coal use and more stringent air and water pollution controls motivated by environmental and health concerns.

Potential adverse impacts associated with landfill disposal include withdrawal of land from productive use, destruction of visual attractiveness, and particulate emission during handling and placement. These effects are not discussed further in this chapter because they are relatively obvious or reasonably amenable to control. The most important problem is potential surface and groundwater contamination by runnoff and leachate, with a consequent degradation of drinking water aquifers and impacts on aquatic and terrestrial organisms.

Problems associated with waste disposal are site-specific because waste properties, dispersal mechanisms, and resources at risk can vary substantially. Variation in waste properties can occur because of differences in mineral content of the coal, options in process design and control, and in waste disposal practices and facility design. Dispersal of the waste is governed by topography, climate and geology. The geologic strata underlying the relatively flat terrain of the Coastal Plan generally constitute a water table aquifer and one or more underlying artesian aquifers, which are often of lesser quality. Waste leachate could enter and contaminate one or more of these aquifers and possibly enter surface streams. On hilly terrain, leachate will tend to seek and follow the underlying natural drainage channel to emerge and enter a nearby stream or pass into the fracture system in the underlying rock. The impact of such waste dispersal would depend on the extent to which the affected aquifers and streams are important for drinking water and ecological purposes.

Waste disposal is governed by both State and Federal regulation. Regulations in each case are complex, inter-related, and in flux; they are enforced through a state permitting process based on the Environmental Protection Agency (EPA) criteria. Utility waste from coal combustion is regarded as a high volume, low hazard waste and is specifically excluded at the state and federal level from designation as a hazardous waste. In most instances such waste can be contained to whatever extent is necessary through engineering measures discussed in Section B. The tradeoffs between reuse, facility siting, and containment of wastes are complicated by rapidly changing regulations, disposal technology and reuse economics.

A. Chemical and Engineering Properties of Flyash and Scrubber Sludge

The need to provide environmentally sound disposal for the principal wastes, flyash and scrubber sludge, is governed by their chemical properties. The manner of providing safe disposal is governed by their engineering properties.

As a hydrocarbon, coal consists principally of hydrogen, carbon, oxygen, nitrogen and sulfur, which will air form gaseous compounds during combustion. The sulfur content of coal commonly used by utilities ranges up to 6 percent. An additional 3 to 30 percent of the coal consists of compounds that fuse and form ash. These are mostly complex aluminosilicates, iron, calcium, sodium and a large number of trace elements.

The liquid resulting from the contact of water with waste is called a leachate. Table IX-1 lists the concentrations of trace elements in ash leachate and compares them with several standards which are likely to be applicable in the vicinity of a disposal site. It is not usually possible to predict the quality of leachate from any particular ash without testing. Laboratory extraction procedures have been developed by EPA (2) and the American Society for Testing Materials (ASTM), and the ability of these tests to predict leachate quality is currently under scrutiny (3).

The principal non-recoverable scrubber sludge component is a mixture of calcium sulfite hemihydrate and calcium sulfate dihydrate ("abatement gypsum"). The calcium sulfite hemihydrate can be converted to the gypsum form by an excess of oxygen in the scrubber or through forced oxidation after it leaves the scrubber. Calcium sulfite is thixotropic (water holding) in nature. If it is left in the unoxidized form, a common option for its disposal is ponding, with an attendant threat to ground water from leachate discharge. It can also be disposed of by blending with flyash alone or by stabilization in a chemical fixation process with flyash and lime. Stabilization is facilitated by oxidizing the sludge to calcium sulfate. Table IX-2

Table IX-1
Representative Trace Elements Concentrations in Coal Ash Leachate[a]

Species	Range mg/l	Mean mg/l	EPA Primary Standard[b] mg/l	EPA Secondary Standard[c] mg/l
Antimony	.002 to .04	.02	---	---
Arsenic	.0001 to .42	.03	.05	---
Barium	.1 to .5	.31	1.0	---
Beryllium	.0004 to .01	.002	---	---
Boron	.17 to 3.2	1.2	---	---
Cadmium	.0001 to .005	.002	.01	---
Chromium	.0006 to .07	.035	.05	---
Cobalt	.0003 to .01	.005	---	---
Copper	.004 to .08	.03	---	1
Fluorine	.2 to 20	5	1.4 to 2.4	---
Iron	.01 to 4.6	.59	---	.3
Lead	.006 to .25	.02	.05	---
Manganese	.001 to .90	.27	---	.05
Mercury	.0004 to .08	.007	.002	---
Molybdenum	.002 to .056	.02	---	---
Nickel	.001 to .12	.04	---	---
Selenium	.001 to .12	.02	.01	---
Silver	.0003 to .01	.004	.05	---
Uranium	.002 to .1	.006	---	---
Vandium	.005 to .23	.14	---	---
Zinc	.01 to .4	.07	---	---

(a) Thirty different coal ash leachates and pond liquors were reviewed.
(b) EPA's National Interim Primary Drinking Water Standards (NIPDWS).
(c) EPA's National Secondary Drinking Water Regulations (NSDWR).

Data from Reference (4).

Table IX-2
Representative Trace Elements Concentrations in Scrubber Sludge Liquor[a]

Species	Range mg/l	Mean[d] mg/l	EPA Primary Standard[b] mg/l	EPA Secondary Standard[c] mg/l
Antimony	.09 to 2.9	.2	---	---
Arsenic	.004 to .3	.009	.05	---
Barium	(e)	(e)	1	---
Beryllium	.0006 to .14	.013	---	---
Boron	.9 to 46	(e)	---	---
Cadmium	.002 to .044	.032	.01	---
Chromium	.005 to .4	.08	.05	---
Cobalt	.1 to .7	(e)	---	---
Copper	.002 to .6	.20	---	1
Fluorine	.7 to 3.0	1.5	1.4 to 2.4	---
Iron	.02 to 8.1	(e)	---	.3
Lead	.001 to .4	.016	.05	---
Manganese	.007 to 2.5	.74	---	.05
Mercury	.0004 to .07	.01	.002	---
Molybdenum	.07 to 6.3	(e)	---	---
Nickel	.005 to 1.5	.09	---	---
Selenium	.001 to 2.2	.14	.01	---
Silver	.005 to .6	(e)	.05	---
Uranium	---	(e)	---	---
Vandium	.001 to .67	(e)	---	---
Zinc	.03 to 2.0	0.18	---	5

(a) Thirteen different sludge liquors were reviewed.
(b) EPA's National Interim Primary Drinking Water Standard (NIPDWS).
(c) EPA's National Secondary Drinking Water Regulations (NDWR).
(d) Underscored values are equal to or greater than most stringent reference standard.
(e) Sufficient data were not available for the meaningful calculation of a significant mean.

Data from Reference (4).

identifies the range of concentrations of trace elements in scrubber sludge liquors (slurry water) from one set of tests and compares these concentrations to EPA drinking water standards.

A common disposal technique for plants that produce both flyash and scrubber sludge is to mix or blend the wastes together and (usually) to "fix" the mix by the addition of lime (5). After a brief setting period the mixture is put at the disposal site and compacted. The fixation reaction is a pozzolonic reaction consisting of the formation of calcium silicate links between the flyash and lime particles. This is the same type of process responsible for the setting of portland cement. The formation of this mixture takes up some of the remaining water in the sludge. In addition, some gypsum may react with the lime and flyash to form a mineral called etrringite. The rate at which leachate can be generated depends on whether the materials are blended or fixed, but leachate concentrations, as illustrated in Table IX-3, are estimated to be the same for either process. It should be noted that for any scrubber waste the use of saline water as makeup to the scrubber could significantly increase the chlorides and total dissolved solids concentrations.

When wastes are to be stored in a landfill, the physical properties of concern include compactibility, shear strength, and permeability. Obviously the greater the compactibility, the more waste can be placed on a single piece of land; the same is true for shear strength, which governs the permissible steepness of the sideslopes of the waste pile. In general all of the wastes discussed here, except untreated unoxidized sludge, can be placed in unconfined piles.

Permeability determines the rate at which leachate may be generated by infiltrating water. Table IX-4 gives illustrative permeabilities for various wastes. Fixed scrubber sludge is generally less permeable than other wastes, but the rigidity of the material is such that differential settlement may eventually cause cracks which would increase the bulk permeability.

A topic of current interest is the extent of trace amounts of radioactivity in coal wastes. Table IX-5 provides an indication of radioactivity present in coal, flyash, bottom ash, and scrubber ash from two power plants. There are indications that radio-nuclides become enriched in the ash (relative to the coal) and tend to concentrate on the finer particles. Draft criteria would label a waste as radioactive should the radium-226 concentration exceed 5 picocuries per gram,or the total single source emission exceed 10 microcuries (6).

B. Disposal Techniques

Power plants produce large volumes of solid waste. The specific quantities depend on many factors, such as the type of furnace, composition of the coal, and type of flyash precipitator. Scrubber sludge may not be produced at all if a utility has the option to burn low sulfur coal; the decision depends upon a number of regulatory and economic considerations. If a scrubber is used, the quantities of scrubber sludge will usually be greater than the quantity of flyash.

Table IX-3

Representative Permeate Concentrations for Blended or Fixed Scrubber Sludge (All concentrations mg/l)

Total Dissolved Solids	8800
Sulfate	1350
Chlorinde	2970
Arsenic	0.094
Cadmium	0.21
Selenium	0.12
Barium	1.0
Chromium	0.001
Lead	0.005
Mercury	0.0005
Silver	<0.001
Iron	0.86
Manganese	2.39
Zinc	5.4
pH	7.5

Data from Reference (7).

Table IX-4

Representative Permeabilities of Utility Solid Wastes

Material	Permeability - cm/sec
Flyash	10^{-4} to 10^{-5}
Fixed scrubber sludge	10^{-5} to 10^{-7}
Blended flyash and scrubber sludge	10^{-4} to 10^{-5}

Table IX-5

Contents of the Various Radionuclides in Coal, Bottom Ash and Fly Ash[a]

	ppm			pCi/g						
	U	Th	K	^{40}K	^{228}Th	^{228}Pa	^{210}Pb	^{226}Ra	^{238}U	^{235}U
Plant A[b]										
Coal	0.71	1.6	806	0.73	0.17	0.17	0.26	0.21	0.24	0.012
ESP fly ash	5.6	15	9400	8.1	1.7	1.7	1.4	2.3	1.9	0.093
Bottom ash	4.6	14	7900	6.8	1.5	1.5	0.58	1.9	1.5	0.072
Plant B[c]										
Coal	2.6	5.0	1660	1.4	0.56	0.55	0.68	0.64	0.85	0.037
ESP fly ash	11	22	7400	6.3	2.4	2.4	2.2	2.9	3.5	0.14
Bottom ash	8.4	19	7200	6.2	2.2	2.1	0.84	2.5	2.8	0.11
Scrubber ash	11	22	7200	6.2	2.5	2.5	2.8	3.0	3.6	0.14
Plant B[c]										
Post-ESP (stack)										
Fly ash (mmd)[d]										
17 µm	16	25	8200	7.0	2.8	2.7	4.3	3.3	5.4	0.17
6 µm	20	31	8600	7.3	3.3	3.5	10	4.6	6.8	0.28
3.8 µm	30	36	8600	7.4	3.3	4.0	14	5.3	10	0.39
2.5 µm	36	38	8100	7.0	3.3	4.2	17	5.9	12	0.50

(a) 10-20% propagated 1 σ error from the mean.
(b) Samples from Plant A; input coal contains 11.3% H_2O, 9.2% ash, and 0.52% sulfur.
(c) Samples from Plant B; input coal contains 6.8% H_2O, 23.2% ash, and 0.46%
(d) mmd = mass median diameter determined by centrifugal sedimentation.

Data from Reference 6.

Table IX-6 shows typical waste quantities for a 500 MWe plant. An acre-foot is a volume one foot high over one acre. As an illustration, thirty years of waste would cover a 150 acre disposal area to a height of almost 50 feet.

Table IX-6
Typical Waste Quantities for a 500 MWe Plant Using 2.5% Sulfur Coal
(Volume in Acre-Feet)

Waste	Annual Volume per MWe	Annual Total Volume	30-Year Volume
Flyash	0.14	72	
Bottom Ash	0.03	14	
Oxidized Scrubber Sluge	0.35	174	
Total: Flyash and Sludge[(a)]	0.49	246	7380

(a) Since bottom ash is often sold for commercial use it is not included in total waste requiring land-fill disposal.

Where wastes are not to be re-used, disposal or long-term storage is necessary at either the plant or an off-site location. Land-filling is the most widely available option for disposal. (The past use of unlined disposal ponds was only a specialized form of landfilling; such ponds in contact with ground water or subject to leaching are no longer likely to meet environmental regulations.) Blending of ash and sludge allows the pozzolanic properties of ash to improve the engineering properies of scrubber sludge and adding lime or "fixing" tends to further harden the resulting product. The special technique of employing fixed scrubber sludge in the construction of artificial reefs is an option still under study and even if viable would only be available to power plants in suitable locations. Ocean disposal is possible, but regulatory attitudes, the cost of transportation, and the permanent loss of a potential resource suggest that off-shore disposal is unlikely to become commonplace. Thus, for Maryland, landfilling will probably be the principal method of utility waste disposal in the immediate future.

Transportation is an important consideration in disposal planning. Scrubber sludge in the form of calcium sulfite is a semi-liquid and can only be transported by slurry pipeline or an especially suited vehicle unless it is first dewatered or stabilized. Sludge in the form of calcium sulfate can be transported as a solid, and ash may be transported either as a solid or a slurry. Solids can be moved by truck or railcar. Slurry transport implies either ponding at the disposal site or that dewatering facilities must be provided. The decanted supernatant can be re-used or must meet discharge standards. Dewatered slurried wastes will still be high in moisture content unless dried, leading to excessive land requirements, unstable waste piles, and leachate release as the pile settles. On the other hand, dry waste disposal may produce fugitive emissions. Increased truck traffic and random spillage are possible added concerns whenever vehicle transport is used. In general there is a trend away from wet disposal systems because of difficulties in meeting environmental regulations.

Rarely is the installation of a properly designed and operated landfill seen as an improvement over existing land uses. Beyond concern for the loss of the site from productive use during active disposal, responsibility for long term use and maintenance also concerns communities in the site vicinity. Future use and maintenance of the site must be part of preliminary planning since suitability for future use can only be guaranteed through proper initial design followed by adequate quality control throughout the operating period.

Structural stability of the waste depends on both the properties of the material and on proper site design and operating procedures. Calcium sulfite remains thixotropic and must be retained in a pond or behind dikes unless dewatered or stabilized. Calcium sulfate is a solid and will stand in a pile, but is subject to erosion and leaching. Flyash is relatively stable and can be piled alone. Additional stability is achieved when flyash is blended with scrubber sludge or fixed with scrubber sludge and lime. In any case proper drainage and dike design must be provided, and allowances made for ground settlement beneath the weight of the pile.

Several options exist for the prevention or reduction of leachate entry into ground water. The formation of leachate may be prevented by capping the landfill with a waterproof material such as compacted clay or synthetic rubber covered by vegetated soil. Sufficient experience is not available on cover durability, but inspection and repair of a cover is feasible since it is accessible. Entry of rain during construction may also require control, but under some circumstances, such as rapid construction with relatively dry waste, the amount of rain water may be small enough to preclude significant leachate generation. If a cap is not used and leachate must be collected, a barrier made of the capping materials mentioned above can be placed between the waste and the ground water with a collection system located in the layer between the two. This system may consist of granular material alone or with a pipe grid collection system added. Both the barrier and the collection systems are susceptible to damage due to settlement, and inspection and repair are nearly impossible. Under some circumstances, fixation of the waste may provide adequate control of leachate generation. Such measures may be unnecessary where leachates will be dispersed.

Where surface water will traverse the open face of the landfill (for example in rainstorms), collection and treatment of contaminated runoff should be carefully considered. Grading to prevent water running onto the waste is good engineering practice.

Just as potential environmental impacts of utility waste disposal vary from site to site, disposal costs also vary, and for many of the same reasons -variability of source coal, variability of plant processes, and variability of the engineering effort needed to protect the resources at risk. The total cost of a waste disposal facility includes the sum of the initial capital costs (purchase of land and equipment, design and licensing, construction),and the total of all operating and maintenance costs throughout the lifetime of the facility. Costs of closure and perpetual maintenance, such as leachate collection and treatment, must also be included. Since disposal facilities have varying lifetimes, total costs among facilities are best compared on a present value basis or on a present value basis or on a cost per unit quantity of waste per unit of electricity generated.

Although it is desirable to present some indication of waste disposal costs, the many factors to be considered in any single situation make a general approach impractical. An illustration is provided here and the reader is referred to estimating techniques published by the Electric Power Research Institute in 1979 for further information (7).

For a 500 MWe plant operating at a 70 percent capacity factor, trucking 299 tons per day of dry ash over one mile of public roads to a landfill without special containment features, the annual cost for flyash disposal is estimated to be, in 1979 dollars, 0.78 million dollars. This is equivalent to $7.15 per dry ton, or 0.255 mills per kilowatt-hour, or $1562 per year per installed megawatt. Wide variability in actual situations may be expected.

For the same plant, burning coal with 12 percent ash and 2.5 percent sulfur, and disposing jointly of 299 tons of ash blended with 399 tons of oxidized scrubber sludge daily in a landfill without special containment features, the total annual cost for disposal of both wastes is 5.15 million dollars, equivalent to $20.22 per dry ton of combined ash and scrubber sludge, or 1.68 mills per kilowatt-hour, or $10,308 per year per installed megawatt. The incremental cost of scrubber sludge disposal is thus $8746 per year per installed megawatt. As noted above wide variability around this estimate may be expected.

C. Environmental Impacts

The most important potential environmental impacts of discharges from utility waste disposal areas are due to elevated concentrations of total dissolved solids, salts and trace elements. Uncontrolled discharges could cause ground water in the vicinity of the site to exceed some of the primary and secondary standards given in Section A. This situation would usually be monitored by wells adjacent to the site. The extent to which discharges are a problem will depend on current and planned future uses of the affected aquifer. In some circumstances such discharges may be unimportant because the aquifer is unsuitable for drinking water purposes in its natural state.

The biological impacts of discharges to surface water are currently under study. A detailed discussion is contained in Chapter 7 of Reference (8). In general there are no indications that even low concentrations of trace elements such as arsenic, selenium and cadmium can cause developmental deformities in fish larvae. Potential releases from disposal areas need to be evaluated on a case-by-case basis to determine the likely extent of impact.

D. Regulatory Status

The regulatory situation regarding the disposal of utility wastes is complex because both the federal and state governments are in the process of implementing broad regulations covering the disposal of many types of waste.

There are still many uncertainties regarding both the philosophy and the technical details of the proposed regulations. At present utility wastes are specifically excluded from classification as "hazardous" and are therefore "solid wastes". The federal requirements for disposal as proposed by the Environmental Protection Agency are less severe for solid waste than for hazardous waste, but are still stringent. A disposal facility must not cause primary and secondary drinking standards shown in Table IX-7 to be exceeded in the ground water beyond the edge of the waste pile or at an alternative boundary set by the State.

Table IX-7
Drinking Water Standards

Primary Standards

Contaminant	Level (mg/l)
Arsenic	.05
Barium	1.
Cadmium	.01
Chromium	.05
Fluoride	1.4 - 2.4
Lead	.05
Mercury	.002
Nitrate (as N)	10.
Selenium	.01
Silver	.05

Secondary Standards

Contaminant	Level
Chloride	250. mg/l
Color	15. color units
Copper	1. mg/l
Foaming Agents	.5 mg/l
Iron	.3 mg/l
Manganese	.05 mg/l
Odor	3 threshold odor No.
pH	6.5 - 8.5
Sulfate	250. mg/l
TDS	500. mg/l
Zinc	5. mg/l

Code of Maryland Regulations require a permit from the Department of Health and Mental Hygiene (DHMH) for discharges to the ground water regardless of the material, but the constraints vary depending on the nature of the material. In general the State can regulate facility design, discharge concentrations and receiving water quality. For the disposal area recently proposed at Vienna, Maryland (see next Section) the preliminary state regulatory criteria include meeting primary and secondary drinking water standards at all depths at the edge of the waste pile and preventing direct contact of the waste with the water table. Discharges to surface waters from a waste disposal facility are also regulated by the State through the NPDES permitting process. The general criterion is that waters must be free from substances in concentrations which are harmful to human, animal, plant or aquatic life. The only applicable specific criterion is pH outside of a designated mixing zone, but other criteria are likely to be proposed on a case-by-case basis.

In addition to the regulation of discharges from utility waste disposal facilities by DHMH and EPA, it is possible that the Maryland Public Service Commission could impose conditions on the siting and operation of such facilities to insure that waste disposal is handled safely and economically.

Compliance with regulations would usually be determined by monitoring the quality of discharge and receiving waters. For ground water such monitoring is complicated because discharges are not readily observable and the concentrations of some constituents in the ground water may exceed standards due to natural conditions or agricultural practices. Baseline monitoring is usually necessary to determine such conditions. A more detailed discussion of the regulatory situation is contained in Chapter 2 of Reference 8.

E. Vienna Example

A study by the Power Plant Siting Program has recently been completed of Delmarva Power's plans for disposal of solid waste for the proposed 500 MWe Unit 9 at Vienna (8). Flyash and scrubber sludge would be blended together to form a damp, soil-like material and disposed of in a landfill at the rate of approximately two-thirds acre-foot per day. After 30 years the waste pile would cover 165 acres to a maximum height of approximately 50 feet. The waste would be placed over a layer of fill to maintain a five foot separation of the waste from the ground water. An impermeable cover would be installed over the waste after emplacement to eliminate contact with rain water. A layer of soil would be placed over the cover and planted with Kentucky 31 fescue.

An artist's sketch of the general features of the waste pile after 30 years of operation is shown in Figure IX-1. The grading would route rainfall runoff from completed area of the landfill to natural drainage. The emplacement procedure for the waste would be to work in ten successive 16.5 acre tracts. Runoff from the active area would be collected in a lined sedimentation basin and recycled into the scrubber system. Analysis indicates that infiltration of rain water during emplacement of the waste would be insufficient to cause the pile to saturate, so no leachate would result. The proposed design is predicted to result in a negligible amount of leachate reaching the ground water or surface waters.

The above design was developed after laboratory and field studies and discussions between the Power Plant Siting Program and the utility. Because of site features such as a high watertable, localized soft foundation soil

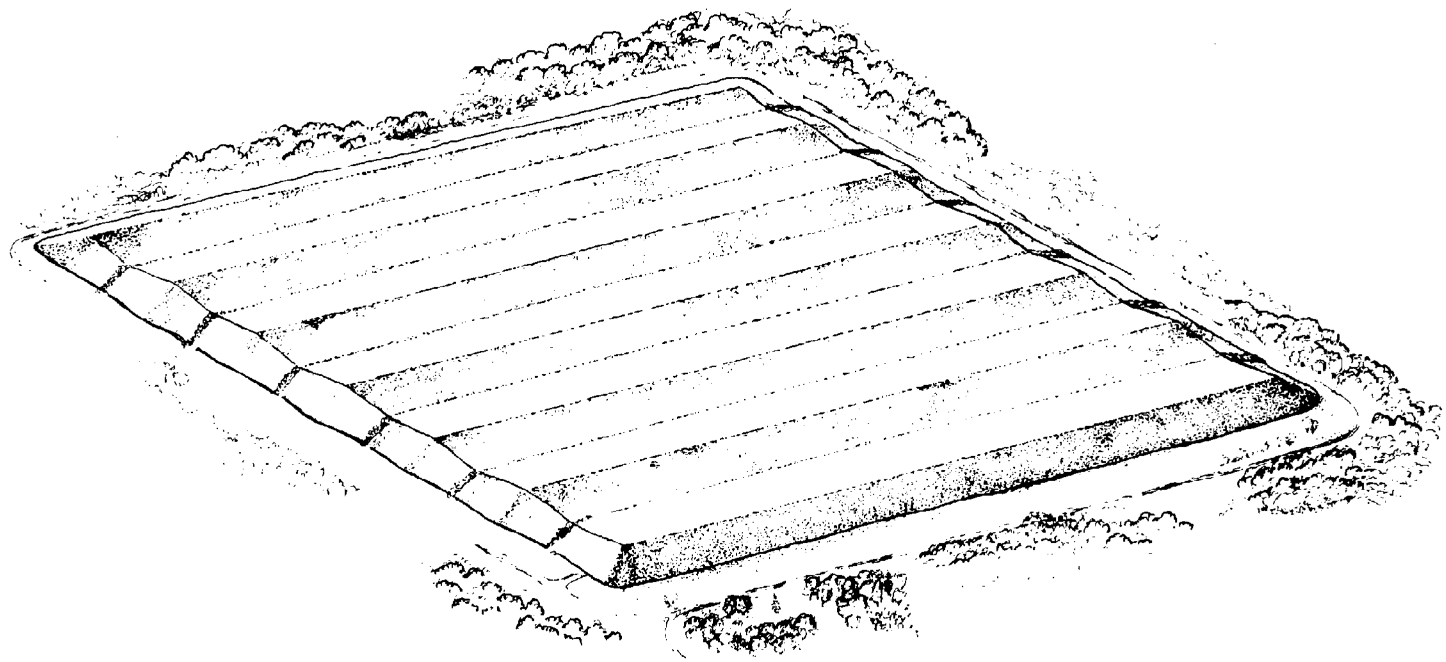

Fig. IX-1 Artist's concept of solid waste disposal area.

and the proximity of important natural resources, usual disposal approaches such as waste fixation or use of an underdrain could not be employed. The facility design was therefore tailored to the characteristics of the waste and the site. The most important aspect of facility design was the study of factors affecting the ability of the cover to prevent infiltration by rain water, such as liner performance, sideslope stability, settlement, and water budget. Another important facet of the evaluation was analyses of dispersion and attentuation of discharges in the ground water and surface water and the resulting biological consequences.

The results of the design study are contained in references 8, 9, and 10. The design concept was found adequate to meet regulations and to prevent contamination of the drinking water aquifer or damage to natural resources in the adjacent surface water bodies.

F. Waste Disposal in Maryland

At present, there are no utility flue gas desulfurization systems operating in Maryland; all of the utility waste being generated is flyash and bottom ash. Currently there are five coal burning plants: Baltimore Gas and Electric Company (BG&E) and Potomac Edison Company (PECO) each has one, and Potomac Electric Power Company (PEPCO) has three. Delmarva Power (DPL) is planning a major new coal-burning facility at Vienna which will include a scrubber. Also, BG&E is planning to burn coal at its new Brandon Shores plant and eventually to convert most of its oil burning plants to coal. Scrubbers will not be used at the Brandon Shores plant because it is exempted from the most recent New Source Performance Standards. The need for scrubbers at the converted BG&E plants and at the future plants of PEPCO and PECO is presently unknown.

Information currently available about the present ash disposal situation is presented below.

- Baltimore Gas and Electric Company

  The Wagner 3 station presently generates 61 acre-ft of flyash and 15 acre-ft of bottom ash annually. When the conversion of the Charles P. Crane station is completed in 1983, 46 acre-ft/yr of flyash and 46 acre-ft/yr of bottom ash will be produced, and in 1988, when Brandon Shores Unit No. 2 becomes operational an additional 191 acre-ft (in the same proportion of flyash to bottom ash) will be generated annually. BG&E reports a continuing effort to market its flyash. In 1979, 10 percent of the Wagner ash was sold, and this amount was doubled in 1980. In 1981, ash from Wagner will be used in the parking lot and road system at the Calvert Cliffs nuclear plant. Earlier, flyash from the Riverside plant was used in the construction of Liberty Dam for the Baltimore City water supply system. It is further anticipated that from 25% to 50% of the ash from Brandon Shores will be marketed.

  Material not marketed in the past was sent to the Boehm-Joy landfill near Crownsville in Anne Arundel County. Since that landfill was closed in November 1980, ash has been sent to a landfill in a sand and gravel quarry near Joppa in Harford County. Unsold material from Brandon Shores is planned to be used as structural fill material near the plant assuming all necessary permits can be obtained.

- Delmarva Power and Light Company

  The Vienna plant on the Nanticoke River where it is crossed by U.S. 50 operated coal-fired units from 1928 until 1972. Coal refuse was deposited in a diked marshland of approximately 90 acres across the Nanticoke River. For the planned addition to the Vienna plant, blended coal ash and scrubber sludge will be placed in an engineered landfill on-site. The landfill design, worked out through negotiations with the Power Plant Siting Program, will keep the waste isolated from groundwater and ambient precipitation and is expected to create no environmental hazard. Environmental review by the Public Service Commission and the Office of Environmental Programs is still required, however.

- Potomac Edison Company

  (Subsidiary of the Allegheny Power System). The R. Paul Smith Plant at Williamsport on the Potomac River in Washington County generates 40 acre-ft per year of flyash and 10 acre-ft per year of bottom ash. These wastes are slurried across the Potomac River to settling ponds, now filled, on the plant site in Maryland.

- Potomac Electric Power Company

  This company operates coal-fired plants at Chalk Point on the Patuxent River in Prince George's County, at Dickerson on the Potomac River in Montgomery County and at Morgantown, also on the Potomac River in Charles County.

The Chalk Point plant has disposal sites both at the plant and at an engineered site nearby in Brandywine. Annual ash production includes 11 acre-ft of bottom ash and 138 acre-ft of flyash. When new precipitators become operational in 1980, these amounts will be increased by 10 percent. Between 1964 and 1971, the ash was disposed of on-site. Since 1971 it has been landfilled at Brandywine.

At Dickerson, annual ash production is 48 acre-ft of bottom ash and 119 acre-ft of flyash. From 1960 to 1967, this material was disposed of in on-site ponds. From 1967 to 1979 the ash was shipped to Pennsylvania, and since 1979 it has again been disposed of on-site.

At Morgantown, annual ash production is 130 acre-ft of bottom ash and 191 acre-ft of flyash. This material has been stored at the Faulkner site on a managed basis since 1974, with unmanaged use of the site extending back to 1971. Earlier disposl sites are unknown but assumed to be on-site.

For the existing disposal sites of each utility it is not possible without further study to determine whether any contaminants exist that are producing leachate in harmful concentrations and whether remedial measures will be necessary. Existing sites are currently under study by the Power Plant Siting Program.

G. Long Term Considerations

Waste disposal areas will require perpetual care. Although the wastes are not legally hazardous, they can cause contamination of drinking water and environmental impacts unless properly controlled. In contrast to some other types of waste, the contaminant level of utility waste in ground water will not decrease to zero over time unless there is a substantial depletion of dissolved materials by release to the environment. It is therefore important to have disposal approaches that minimize routine maintenance and are relatively immune to extremes in natural conditions such as storms. From this point of view facilities that require the collection and treatment of leachate or the active maintenance of drainage systems are undesirable. But even facilities which require no direct routine care are subject to eventual failures from causes such as erosion and deterioration of materials. Therefore institutional arrangements to insure maintenance, prevent disturbance of the facility, monitor for releases and provide for possible reuse of stored materials are important.

Institutional arrangements include such topics as the mechanism of ownership, management responsibility, liability, regulatory responsibility, insurance, and the posting of bonds. The State of Maryland is currently in the process of drafting a comprehensive solid waste management plan which should address these considerations.

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CHAPTER X

TRANSMISSION LINES

Environmental impacts of a transmission line may arise from the construction or presence of the line, from the maintenance of the right-of-way, or from electromagnetic effects associated with the operation of the line. Construction and maintenance may lead to effects on vegetation, wildlife, and fish populations. The presence of a transmission line can potentially impact land uses and values, and also be a visual intrusion. Electromagnetic fields generated in the vicinity of high voltage transmission lines can cause:

- Audible noise
- Radio and television interference
- Ozone production
- Spark discharges to persons touching large, ungrounded metallic objects located in or near the transmission line right-of-way

Electrical fields under transmission lines may create health effects although the existence of such effects have not been confirmed.

Transmission lines are necessary to transmit electrical power from generating stations to the electrical distribution grid, and compose that part of the distribution system operating at 69 kilovolts (kV) and higher. Lines energized at less than 69kV are distribution lines, and form the network that actually brings electricity to the customer.[1] Prior to constructing a transmission line of voltage greater than 69kV, a utility must obtain a Certificate of Public Convenience and Necessity from the Maryland Public Service Commission. The utility must demonstrate, in a public hearing, the need for the transmission line, and the acceptability of the route being proposed. These issues, especially that of route acceptability, are independently evaluated by various State agencies, including the Power Plant Siting Program. A map of transmission lines of 230 kV and higher in Maryland is shown in Figure X-1.

A. Environmental Impacts

The construction of a transmission line will inevitably cause some environmental impact, but there are several ways by which such impact can be minimized. The first and most obvious way is judicious routing. Identifying a transmission corridor which avoids those areas considered to be unique or environmentally very sensitive obviates the need for special mitigating actions. Performing route selection studies, such as that done in conjunction with the Potomac Edison Company's application to construct the Montgomery - Damascus - Mt. Airy transmission line (1) is useful for identifying

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[1]While 69KV is a transmission voltage by definition, it can be utilized for either transmission or distribution.

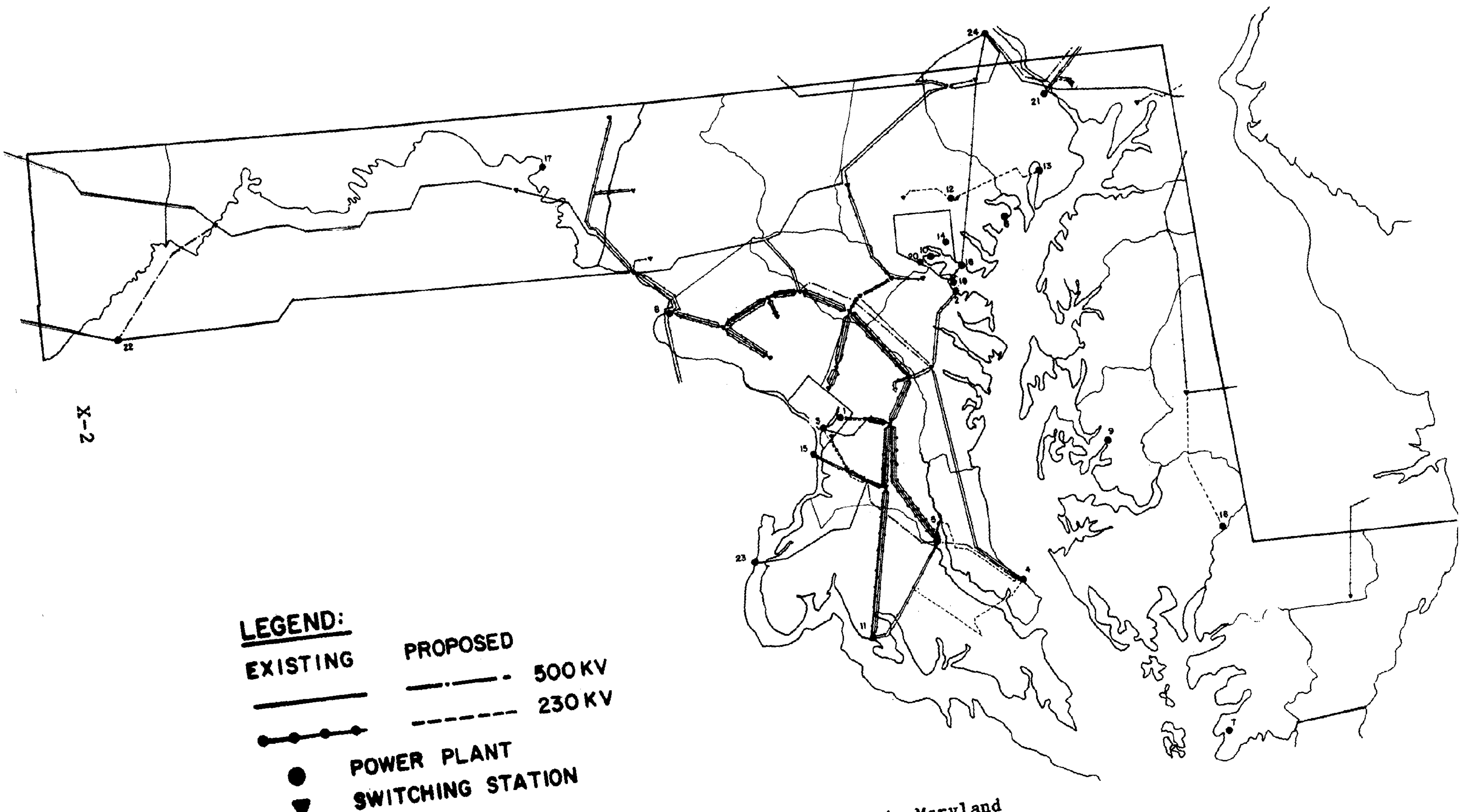

Fig. X-1. Transmission Lines in Maryland available options and tradeoffs necessary for choosing the most acceptable route. Several techniques are available for performing such studies, and the most appropriate is best selected on a site specific basis (2).

One of the most obvious environmental impacts associated with construction of a transmission line is the deforestation which occurs when a right-of-way (ROW) is being cleared. While the location of the ROW will dictate the extent to which land must be cleared, it is difficult to conceive of a route not requiring the removal of some trees. Since deforestation is a problem of increasing magnitude in eastern states such as Maryland, the area of woodlands to be removed becomes a crucial factor in comparing right-of-way alternatives.

Reducing forested areas, while an adverse impact in itself, can lead to secondary effects such as alteration and/or elimination of wildlife habitat, and increased erosion. Wildlife habitat may be altered by ROW clearing, but a habitat is rarely totally eliminated. Species diversity can actually increase when forested areas are interrupted by a corridor populated by shrub and bush species. Exactly how such a habitat change will affect local populations depends upon many factors.

Clearing of a ROW may also affect fish populations. Such effects are of two types: introduction of excess sediments to waterways because of soil erosion, and warming of waters as a result of the elimination of shade trees. Increasing the temperature of a stream can render it unsuitable for existing fish populations. This is most important in the case of natural trout streams. Introducing sediments to waterways can have an adverse impact on the spawning of resident and migratory fish. Sediment blanketing of eggs has been documented as a cause of increased mortality during spawning (3). This is a severe problem in areas composed of highly erodible soils. Mitigative measures, however, are both simple and effective. Seeding and mulching immediately following soil exposure, and restricting construction to the summer growing season should limit sediment damage (4).

Once a transmission line is in place, wildlife can be impacted by the presence of the line and ROW maintenance. A transmission line can, for example, effect birds in flight. Collision related deaths are known to occur, and may be significant on species with dangerously low populations, where any added source of mortality is nontrivial (5). Several site specific factors influencing the frequency of waterfowl collisions have been identified: number of birds present, visibility, species composition, behavior, disturbance, and familiarity with the area (6). There are many uncertainties associated with this problem, but one should weigh the desirability of avoiding those environmentally sensitive areas which can be identified.

Some impact to wildlife will occur as a result of ROW maintenance, which is necessary to prevent vegetation from either compromising transmission line safety, or restricting ROW access. Several techniques, including winter burning, mowing, hand clearing, and selective basal or aerial spraying of chemical herbicides, are commonly used for maintenance. Use of chemical herbicides holds the potential for environmental problems, but recent development of fairly innocuous herbicides, and care in using them can eliminate any undesireable impact. The use of selective basal spraying is generally preferred to broadcast spraying. The Power Plant Siting Program recommends that certificates granted for the construction of transmission lines restrict the use of chemical herbicides to selective basal application.

The aesthetic impact associated with the presence of a transmission line has become a very contentious point in several Public Service Commission hearings. Such impacts are inherently subjective and vary greatly, but invariably invoke very emotional responses from some of the affected individuals. While it has been shown that some people do not wish to see transmission lines, the assumption that transmission lines are intrusive and that no-one wants to see them is unproven (7). Unfortunately, regardless of the route selected, there is usually some aesthetic impact.

Although this impact is very subjective in nature, many technical factors affect its severity. The appearance of a transmission line is a function of such engineering factors as voltage, line configuration, number of circuits, and number of conductors per phase, and such external factors as the vegetation and topography which characterize the ROW. In addition, the structures used for transmission lines range from a single wooden pole to latice steel towers of heights exceeding 150 feet. All of these factors also result in great variation in the width of the ROW. Because of this, the extent to which a transmission line visually impacts an area varies greatly.

Because of the potential for aesthetic impact, and the expense of obtaining rights-of-way, transmission lines are generally located away from urban centers. This generally results in a reduction in the number of people whose surroundings are negatively affected. Unfortunately such routes can result in a more significant deterioration of what was formerly a very scenic area. Areas where viewers would be especially sensitive to the presence of a transmission line, e.g., National or State forests and parks, scenic rivers, and sites of historic or cultural significance, can generally be avoided during the route selection process.

Attempting to avoid creating a visual impact can itself actually result in environmental impact. For example, scenic impacts are often reduced by locating transmission lines in low lying areas. Unfortunately streams also tend to be located in low lying areas. Routing around such areas can result in placing a transmission line on land considered to be highly desireable for various human activities, such as agriculture and development. This causes an inevitable conflict over land use.

Whenever a transmission line passes through or in close proximity to residential areas or land proposed for residential development, it is typically claimed that a transmission line adjacent to a lot will drastically reduce the value of the property, possibly even rendering it unsellable. Several studies have been undertaken to determine if there actually is a direct relationship between proximity to transmission line and property value. There are numerous studies supporting both the contention that the presence of a transmission line adjacent to a residential lot will cause a reduction in property value (8), and that no such reduction will result (9). A study done in Maryland for PPSP found a slight reduction in one community and no effect in another (10). While these effects can occur, although they are usually small, there is great variance from case to case.

Another consideration is the effect on agricultural operations. Although the impact is generally minimal, a transmission line spanning agricultural lands can result in a loss of productivity. Such losses result from land lost around structures and guy wires, adverse effects on soil profile and drainage from construction, structure interference with harvesting patterns, and weed propagation around structures (11). In addition, aerial operations for crop control in the vicinity of a transmission line will be restricted.

Obviously, there are some unavoidable impacts associated with the routing of any transmission line, and not all can be mitigated by judicious routing. Selecting a route requires tradeoffs between the various potential impacts. Any areas where the impact would be unacceptably severe can generally be avoided in the route selection process.

B. Electrical Effects

The operation of a transmission line has certain electrical effects on its surroundings. These effects usually are negligible at voltages below 230 kV, and can be divided into two categories: corona effects and field effects.

Corona discharge occurs at the conductor surface because local field strengths at some points on the conductor become great enough to ionize air. Such concentrations of field strength are enhanced by surface irregularities, e.g., dirt, scratches and water droplets. Corona discharges result in such electrical effects as audible noise, radio and television interference, and ozone production (12). Each of these effects becomes more severe in wet weather, a result of the increase in water droplets on conductors.

Audible noise occurs as a buzzing sound under very high voltage lines, such as those 500 kV and greater. Noise levels will tend to reach a maximum during periods of fog or mist, and are lower during dry weather. During heavy rain the loudness of the rain itself exceeds noise generated by the transmission line. While the posibility of annoyance to nearby residents cannot be discounted, it is nonetheless highly unlikely to occur.

The electromagnetic energy in corona discharges can cause interference with radio or television reception. This effect is generally significant only during wet weather, and is principally associated with voltages of 500 kV and greater (although it can occur on lower voltage lines, especially if they are older). Radio interference can be experienced by residents located near a transmission line as a reduction in quality of AM reception, but rarely during fair weather. Television interference near 500 kV lines has been shown to be a problem only when the following conditions exist: 1) television set located less than 300 feet from ROW; 2) indoor antenna only; 3) tuned to low frequency stations (channels 2 through 6); and 4) in use during rain (13).

The other result of corona discharge is the production of ozone from normal oxygen. The production efficiency varies greatly, and is dependent upon line voltage, electric field strength, conductor geometry, conductor surface condition, and meteorological conditions. Attempts to detect ozone, a highly reactive gas, produced by corona discharge have generally failed. Under worst case conditions, concentrations averaging less than 1 ppb above peak background fluctuations have been found (14). Ozone produced by transmission lines is not expected to have any significant effect on ambient air quality.

Field effects can result from either electric fields or magnetic fields which are created around the conductors. Electric fields are basically a function of line voltage, while magnetic fields are basically a function of conductor current. These fields can cause transfer of electrical energy through induction to conducting objects within the fields.

Both electric and magnetic fields contribute to induction on conducting objects, although the mechanisms vary. Induction from magnetic fields is important on long conductors with a connection to ground (such as fences), while electric fields tend to effect conducting objects which are well insulated from the ground (such as motor vehicles).

People touching objects on which voltages have been induced may experience noticeable effects as a result of induced currents or spark discharges. The magnitude of these effects ranges from the threshold of perception, to actual discomfort or startle reaction. Under worst case conditions, induced currents can theoretically reach levels (the "let-go" threshold) at which hand and arm muscles involuntarily contract, preventing one from releasing one's grip. These levels are, however, usually far higher than those induced by transmission lines on objects such as long fences.

More likely to be a problem, but still typically one of discomfort or annoyance rather than an actual safety hazard, is the spark discharge experienced from touching a conducting object on which a voltage has been induced. The associated sensation is not unlike that experienced when touching a metallic object after walking across a carpeted room in winter. A hazardous situation might arise if someone climbing a ladder on a house near a transmission line touches a gutter on which voltage has been induced, the individual may be startled and fall down. Several conditions must be met before this accident could be expected to occur; one example meeting the proper conditions would be a house 40 feet long with a raingutter 15 feet high, and located 120 feet from the center of a 500 kV ROW. While only preliminary work has been completed, a detailed study is now being undertaken to define exactly how people react to short duration, high voltage shocks (15).

A spark discharge could possibly ignite gasoline vapors given the proper conditions. This highly unlikely event requires conditions such as refueling of a large gasoline powered vehicle under a transmission line where the electric field strength is 5 kV/m or greater. The vehicle would have to be well insulated; e.g., standing on asphalt or crushed stone, the individual refueling the vehicle would have to be well grounded, e.g., standing on damp earth, the gasoline vapors and air would have to be mixed in proportions necessary for combustion, and the neck of a metal gas can would have to come close enough to the vehicle to cause a spark discharge. The Public Service Commission did consider a recommendation that conductor heights above surfaced roadways be raised to a minimum of 50 feet because of the possibility of fuel ignition, but ruled that the likelihood of such an event did not merit altering the existing 42 foot minimum height standard.

C. HEALTH EFFECTS

Transmission lines rated at 345 kV and above have been in existence for about 30 years. No health hazards to the general public exposed to the electric and magnetic fields produced by these transmission lines have been documented. Effects from long-term exposure to these fields could nonetheless exist.

Concern about this intensified in the early 1970s when reports of adverse health effects on workers in 500 kV and 700 kV switchyards were received from the Soviet Union. Various individuals have suggested that these studies prove that field strengths associated with transmission lines pose a health hazard. However, similar studies with workers in the United States, Canada and other countries have failed to reproduce the Soviet results, and more recently, some Soviet experts have expressed doubts about the earlier work from their country.

Of the many projects to look for effects of power frequency fields on laboratory animals, some found associated health effects and others did not. It is important to resolve questions as to whether the fields from high-voltage transmission lines can have long-term effects on humans or animals. To this end the utility industry, various governmental bodies, and others have initiated broad and extensive research programs. It is hoped that these programs will resolve most of the existing issues, and in the near future permit an improved assessment of any risks resulting from long-term exposure to transmission line fields.

Although no direct health effects associated with electric and magnetic fields have been identified, some states have chosen to set limits on the strength of fields permitted under transmission lines based upon consideration of shock effects. Both Oregon and Minnesota have maximum permissible field strengths with a right-of-way, 9 kV/m and 8 kV/m, respectively, while New York has effectively limited field strengths to 1.6 kV/m at the right-of-way edge (16). Oregon has actually limited field strengths by law; the other restrictions have come in required construction permits. Current acceptable National Electrical Safety Code clearances would probably keep the maximum induced field to less than 10 kV/m. Typical values for maximum field strengths under powerlines in Maryland are 7 to 7.5 kV/m. No limits have been imposed in Maryland.

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CHAPTER XI

COOLING TOWERS

Two general types of condenser cooling systems are currently in use at Maryland power plants. Open or once-through systems predominate. Cooling towers are alternatives which may be required by Maryland law. Cooling towers require less water to operate (as much as a 50 fold reduction), so their aquatic impacts are considerably reduced as discussed in Chapter IV. They could, however, have adverse terrestrial impacts that require site specific evaluations.

Cooling towers can use natural draft or fan-induced, "mechanical" draft. Both types remove heat by evaporation. In the process an aerosol is created which may drift beyond the exit point of the tower. This drift may contain concentrated dissolved solids as well as the chemicals used in biofouling control. Concentrated saline aerosols resulting from cooling tower operation in brackish water regions of the Bay could have an adverse impact on native vegetation, crops, and soils. Fogging and icing may occur under certain meteorlogical conditions and must be considered when highways or buildings are within the plume impact region. Noise impact, created by cascading water (natural and mechanical types) and fans (mechanical type) on neighboring communities, must be evaluated. Visual impacts of cooling towers and plumes must be considered within the context of existing visual elements at the site.

Chalk Point plant has two natural draft towers. The proposed expansion of Vienna will also use a natural draft tower. Present and predicted impacts at each site are discussed below.

A. Chalk Point

Chalk Point Unit 3 is equipped with a natural draft cooling tower. It has operated in a brackish water region of the Patuxent since 1975. This unit also emits brackish water steam from a stack scrubber. Drift emissions from the stack is approximately equal to the emission from the tower. Detailed studies have been made of the extent of this salt drift and its effect on crops, soils and native vegetation in the vicinity of the plant. These studies show that maximum deposition occur within 1 km of the source. This distance is within the plant boundary and the measured deposition rate of 8 kg/ha-month is below the rate at which commercial crops (soybeans, corn and tobacco) exhibit foliar damage (20 kg/ha-month). There appears to be no buildup of Na^+ or increases in electrical conductivity of the soil due to dustfall accumulation (1). Experimental studies using five species of native woody trees showed an increase of Na^+ and Cl^- with increased exposure to saline aerosol. In all species, except dogwood, the accumulation levels of Cl^- at the end of a growing season were less than the levels causing foliar damage (0.4-1.8% on a dry weight basis). Normal autumn color in dogwood, however, obscured observations (2) of any foliar damage due to Cl^-.

Unit 4 at Chalk Point is also equipped to operate with a similar cooling tower, but it has not operated to date. The predicted off-site deposition from cooling towers and stack drift from both units is estimated (3) to be less than 5 kg/ha-month.

B. Vienna

A natural draft cooling tower has been proposed for DP&L's 500 megawatt coal fired expansion at Vienna. The issues of salt deposition, plume visibility, fogging/icing, and visual intrusion were considered by PPSP for natural and mechanical draft cooling towers.

The Chalk Point Cooling Tower Drift Simulation Model was used to predict salt drift both on and off site at Vienna for the optimal type of cooling tower (natual draft). Maximum off-site deposition rate occurred in the autumn and was less than 25 kg/ha-month. No significant accumulation is predicted to result from this amount. Reduction in crop yield of corn and soybeans is estimated to be on the order of a few percent. Weathering and corrosion of materials at the boundary will be similar to that found at sites 1 km inland from the ocean coast (4).

The impact of visual intrusion of the cooling tower and related plume is difficult in quantify. The tower itself will be 122 meters high, and on most days the plume will exceed 100 meters in length. The visual impact of the tower and plume, however, must be considered as an incremental visual impact in addition to the 171 m stack, turbine (30.5 m) and boiler buildings (76.2 m) of the proposed facility. Because of vacation traffic along Route 50, the number of people exposed to the view could be as high as 14,000 per year. Fogging and icing on the Route 50 bridge is expected to be minimal because of the plume elevation.

On the basis of these studies, the PPSP has recommended to the Maryland Public Service Commission that a natural draft cooling tower be used at the proposed Vienna expansion (5).

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APPENDIX A

THE PPSP/DSP LOAD FORECASTING PROGRAM

Since 1974 the Power Plant Siting Program, in conjunction with the Maryland Department of State Planning (DSP), has conducted an active load forecasting program. During this time period long-range forecast studies of each of the four major utility systems which operate in the State have been prepared (1), (2), (3), (4). These studies provide comprehensive and detailed projections of future electric energy use for each of the four systems. In each case, the forecasts were prepared for the entire multi-state system rather than just the Maryland portion because each of these utilities is planned on a systemwide basis. In addition to developing the annual peak demand forecasts, energy sales were forecast by major customer class, regulatory jurisdiction and season. The PPSP/DSP forecasts were obtained from a set of econometric equations which relate key explanatory variables to the demand for electricity. It is the purpose of this Appendix to describe the methodology and the forecasts it has produced.

PPSP has produced long-range forecast studies for Pepco (1975), BG&E (1979), APS (1980) and DP&L (1980). Revisions have been prepared for Pepco, BG&E and APS. The two most recent studies were the DP&L forecast completed in March 1980, and the APS forecast, completed in January 1980. Since those two studies were completed within a few months of one another, the methodologies employed are substantially similar. This Appendix uses the DP&L models to illustrate that methodology since it is the most recent of the four studies.

The BG&E and Pepco studies were prepared several years earlier, and thus are methodologically somewhat different from the DP&L and APS studies. The Pepco study was completed in 1974 using a data base which ran through 1972. The BG&E study was substantially completed in late 1977, although the report resulting from the study was published by PPSP in 1979. The terminal year of the BG&E data base was 1974.

PPSP has performed forecast updates of the Pepco and BG&E systems in 1978 and 1981, but those revisions are limited in scope. They involved alterations to the forecasting assumptions along with the use of a more recent base year. The updates provide revised energy and peak demand forecasts for Pepco (through 1991) and only peak demand forecasts for BG&E (through 1995).

Because the original studies were prepared so long ago and used little or no data from the post-Arab Oil Embargo period, completely new forecast studies of the two utiities are needed. The new studies will use the more complete data which are now available and will also use any methodological improvements which have taken place in the last few years. PPSP is currently in the process of performing a new Pepco load forecast. Completion is scheduled for September 1982. A revision of the BG&E forecast will also be prepared, scheduled for completion in March 1982. This revision will rely upon the models from the original study but will employ a more recent base year and updated assumptions.

A. Overview

The process of econometric forecasting consists of two principal stages. In the first stage, statistical models of the demand for electricity are estimated from historical data. These econometric models describe the relationship between the demand for electricity and various causative economic factors that govern it, such as population, income, employment, wage rates and energy prices. In the second stage, projections of future values for these causative factors are inserted into the econometric models in order to determine the likely future demand for electricity.

In order to construct a structural econometric model, it is first necessary to determine the important causative factors affecting the demand for electric power. After specifying a model which incorporates these factors, historical data on the dependent and independent variables are collected and processed. The precise quantitative relationships between the dependent variable, i.e., energy consumption, and the factors that govern it are estimated by the use of ordinary least squares regression. In the recent Delmarva study, such models were developed for summer and winter residential usage (per customer), summer and winter commercial usage (per nonmanufacturing employee) and industrial usage (per manufacturing employee). The study also included a statistical analysis of other, less important elements of electricity demand, as well as energy losses, and summer and winter system peak demands.

The econometric equations are derived from the behavioral relationships governing the demand for electricity, as they existed during the period from which the historical data were drawn, generally the mid-1960's to the mid- or late 1970's. The demand forecasts are then calculated by inserting into the estimated equations the expected future values of the driving (causative) variables. Most of these values have been developed from official state or federal projections, including those of the Department of State Planning. The remaining values were determined judgmentally. After the energy forecasts are calculated, these values are inserted into the equation which relates peak demand to energy usage, relative sector size and weather. In that manner projected peak demand is determined. Using values of the driving variables determined in this manner, the Most Likely Case forecast is produced.

It is critically important, however, that system planners and regulators realize that any forecast is uncertain, regardless of how skillfully the models are developed. In order to obtain alternative upper and lower bound growth paths, substantial but plausible alterations to the Most Likely Case assumptions are made and the forecasts recalculated. The difference between the upper and lower bounds represents the plausible long-run range of uncertainty. In addition to these alternative forecast scenarios, the PPSP/DSP studies include estimates of demand reductions (both total energy sales and peak demand) due to conservation programs and time-of-use electricity pricing.

B. The Econometric Models

The econometric models used to forecast energy usage have been formulated on the basis of *a priori*, theoretical judgment concerning the various economic and other factors which directly affect energy usage. Since the models in all cases are estimated from historical time-series data, the results reflect the behavioral relationships that prevailed during that historical period. It is assumed that these historical relationships will prevail in the future.

The development of the PPSP/DSP models has been guided by technical considerations normally encountered in the econometric analysis of electricity demand. These considerations relate to both the limitations of economic modeling, and to the statistical properties of ordinary least squares regression, the estimation method used to quantify the models.

- Specification -- Ideally, an econometric model should be fully specified. This means that all factors which significantly influence demand should be included in the model. Failure to do so will result in coefficients which may be biased, since the remaining variables will be forced to "explain" what the missing variables should explain. However, it is not practical to construct a model which includes the entire universe of possible considerations. Therefore, judgment is required to keep the models as simple as possible without excluding the truly important factors.

- Dynamic behavior -- The rubric of specification includes the "functional form" of the equation as well as the selection of variables included in the model. Since time-series data are being analyzed, there is an opportunity (as well as a necessity) of determining how rapidly households and businesses alter their power demands in response to changes in the causative variables. Since electricity is consumed only through stocks of electricity-using equipment, and since customers will only alter these stocks gradually, the electricity demand responses to changes in the causal variables will likewise be gradual. A model which fails to take this dynamic behavior into account is badly misspecified and will likely produce erroneous results.

- Multicollinearity -- A problem common to time-series regression analysis occurs when two or more independent variables are highly correlated with one another. It is very important that this situation be avoided since it may render the coefficient estimates of one or more of the correlated variables involved erroneous. If the problem is sufficiently serious, one or more of the correlated variables may have to be eliminated from the equation.

- Electricity price definition -- A key assumption in regression analysis is that causation runs solely from the independent to the dependent variable. If causation runs the other way or both ways then biased results are likely. Because electricity has historically been sold from declining block tariffs, this problem is familiar to analysts of electricity demand. With the declining block rates, a random factor, such as unusually hot weather, causes an increase in consumption and thus a decline in the average price paid per kilowatt hour for electricity. Thus, in this example, the increase in usage caused the reduction in price, not the other way around. This problem can be overcome by avoiding an average revenue definition of price.

- Aggregation -- The estimated equation should be derived from data which are not so aggregated as to camouflage important causal relationships. That is, the very act of aggregating can eliminate the variations in the dependent and independent variables needed for efficient econometric estimation. In the PPSP/DSP models this has been avoided by disaggregating by season, customer class and regulatory jurisdiction. How far disaggregation should go depends upon data quality (and availability) as well as theoretical or econometric considerations.

The PPSP/DSP econometric models were specifically designed to avoid these potential pitfalls to the extent possible. The way in which this was accomplished is described below, with special reference to the Delmarva study.

Residential Models

The important determinants of residential usage of electricity can be easily identified and would include:

- electricity prices
- alternative energy prices
- personal income
- population
- weather
- housing stocks
- household appliance stock ownership
- appliance vintages and energy efficiencies
- natural gas available
- household size
- inflation

However, it would be rather unwieldy to include all these items in a regression model, and moreover a reliable historical data series on many of these items is not available. Further, some of the variables (e.g., income and appliance stocks) are interdependent in a complicated manner and thus not truly independent of one another.

These problems can be largely avoided by the inclusion of a "lagged dependent variable" -- i.e., the value of the dependent variable the previous year. The lagged dependent variable serves as a proxy for appliance and housing stocks, lifestyle and other factors which are capable of changing very gradually. This specification also serves to introduce a dynamic adjustment process into the model in a convenient manner.

The residential equations in the Delmarva study were estimated from pooled time-series cross-section data. That data series consists of individual observations for each month 1966-1977 for each of the three states which comprise the Delmarva Peninsula. Separate equations were developed for the summer and winter seasons. Explanatory variables in the models include the number of customers, real (i.e. inflation adjusted) income, real electricity prices, weather, an air conditioning or space heating saturation measure, and a dummy variable for each region.[1] Logarithmic transformations were performed on the dependent variable (monthly sales per customer), real income and the price of electricity. The estimated summer and winter equations along with certain test statistics are presented in Table A-1.

The specification of the weather variable, the lagged dependent variable and the electricity price measure warrant additional explanation. The lagged dependent variable is defined as the value of the dependent variable for that region exactly twelve months prior. The weather variable is specified in first difference form. In order to obtain an "effective" weather measure, the heating degree day values were multiplied by one plus the electric space heat saturation percentage, while the cooling degree day values were multiplied by one plus the air-conditioning saturation.

Finally, the price measures were specified so as to avoid the two-way causation problem described earlier. This requires avoiding the use of an average revenue measure. Therefore, the summer model uses a "marginal price" constructed by subtracting a 500 Kwh monthly bill from a 1000 Kwh monthly bill, and the winter model simply uses a 500 Kwh monthly bill.[2]

Both short and long-run elasticities can be calculated. The elasticities obtained, as shown below, are consistent with although somewhat below the results obtained in other studies. Both the price and income elasticities are slightly lower in the winter.

Summer Season

	Price	Income
Short-run:	-0.09	0.21
Long-run:	-0.40	0.95

Winter Season

	Price	Income
Short-run:	-0.05	0.09
Long-run:	-0.33	0.62

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[1] A dummy variable operates in a binary fashion, taking on a value of 1 when operative and zero otherwise. This approach essentially allows for a separate intercept or constant term for each geographic region.

[2] The monthly bills were constructed from DP&L tariffs in each jurisdiction and fuel adjustment charges.

Table A-1

Delmarva Residential Energy Forecasting Models

Summer

$$\ln(RMWH/CUST) = \underset{(-2.4)}{-0.99} - 0.0004\,CDD + \underset{(19.3)}{0.78}\,LDEP$$

$$\underset{(-2.7)}{-0.09}\ln PRICE + \underset{(2.0)}{0.21}\ln INCOME + \underset{(0.7)}{0.04}\,DVA$$

$$+ \underset{(1.2)}{0.04}\,DSD + \underset{(1.0)}{0.03}\,DMD$$

R^2 = .92 Durbin-Watson = 1.94

Winter

$$\ln(RMWH/CUST) = \underset{(-1.2)}{-\,0.66} + \underset{(32.7)}{0.86}\,LDEP - \underset{(-1.2)}{0.05}\ln PRICE$$

$$+ \underset{(1.3)}{0.09}\ln INCOME + \underset{(9.0)}{0.0002}\,HDD + \underset{(2.4)}{0.06}\,DMD$$

$$+ \underset{(1.3)}{0.05}\,DVA + \underset{(2.0)}{0.05}\,DSD$$

R^2 = .94 Durbin-Watson = 1.56

Variable Definitions

RMWH = Monthly Sales in Mwh
CUST = Number of residential customers
LDEP = Lagged dependent variable
PRICE = Electricity price measure in real terms
INCOME = Personal income in real terms
HDD = Heating degree day measure
CDD = Cooling degree day measure
DMD = Maryland region dummy variable
DVA = Virginia region dummy variable
DSD = Southern Delaware region dummy variable

Numbers in parentheses are t-statistics.

Commercial/Industrial Models

In contrast to the residential sector, the commercial and industrial classes are extremely heterogeneous. Although this heterogeneity warrants a highly disaggregated approach, lengthy time-series on energy usage are usually available only for broadly defined "commercial" and "industrial" customers. The Delmarva study developed separate equations from time-series data for commercial, industrial and other (mainly resale) customers for each of the three states on the Peninsula. Separate summer and winter equations were estimated for the commercial sector, but since seasonality is relatively unimportant in the industrial sector, only annual models were developed. Because of the relative month to month stability in industrial sales, those equations were estimated from quarterly rather than monthly observations.

The character and pattern of nonresidential electricity usage differs markedly from the residential, but the underlying determinants are analogous. Instead of household appliance stocks, power usage by firms tends to be governed by technology and the stock of capital goods which embodies that technology. Thus, it is convenient to specify a model with a lagged dependent variable to serve as both a surrogate for technology and to impart a dynamic response to changes in the values of the causative variables.

Nonresidential model specification is consistent with the standard economic theory of production. The demand for electricity is determined by the level of economic activity (represented by an appropriate measure of employment), and the technology utilized is ultimately determined by relative prices paid for the various production inputs. Thus, in addition to employment and a lagged dependent variable, key explanatory variables would include electricity price and the wage rate.[1]

Several short-run or transitory factors were also included in some of the equations. All commercial equations included a weather variable since commercial electric loads are weather sensitive. Two other variables were employed to account for short-run changes in labor productivity (and thus energy usage) which would normally be masked by an employment variable. A capacity utilization variable was used for that purpose in the industrial sector, reflecting the fact that employment tends to lag behind output over the course of the business cycle. In the commercial sector, an employment change variable was used since marginal or part-time workers are generally disproportionately discharged during a business downturn and hired during an upturn. Consistent with the model in the previous section, these short-run variables are specified in first difference form.

The estimated commercial/industrial models are shown in Table A-2 along with some key test statistics and variable definitions. Because of the marked difference in the nonresidential sector from state to state[2] the use of pooled data was avoided. All models were estimated from time-series data covering the period 1966-1977.

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[1] Rapid increases in the wage rate encourage the use of more capital intensive production methods which, in turn, tend to be more energy intensive.

[2] For example, the industrial sector in Maryland is largely light industry, particularly food processing. By contrast, Delaware is dominated by heavy industry such as chemicals, metals and automobiles.

Table A-2

Delmarva Study
Commercial/Industrial Model

(1) Delaware Commercial Summer Model

$$\ln(\text{MWH/CEMP}) = \underset{(-0.27)}{-0.06} + 0.0004\ \text{CDD} + \underset{(19.6)}{0.77}\ \text{LDEP}$$

$$\underset{(0.97)}{0.11}\ \ln \text{WAGE} - \underset{(-1.21)}{0.06}\ \ln \text{PRICE}$$

R^2 = .88   Durbin-Watson = 1.84

(2) Delaware Commercial Winter Model

$$\ln(\text{MWH-CEMP}) = \underset{(20.5)}{0.80}\ \text{LDEP} + \underset{(1.13)}{0.07}\ \ln \text{WAGE}$$

$$\underset{(2.27)}{0.00004}\ \text{HDD} - \underset{(-2.43)}{0.06}\ \ln \text{PRICE}$$

R^2 = .88   Durbin-Watson = 1.40

(3) Maryland Commercial Winter Model

$$\ln(\text{MWH/CEMP}) = \underset{(30.55)}{0.89}\ \text{LDEP} - \underset{(-5.18)}{1.04}\ \text{CH} + \underset{(0.63)}{0.02}\ \text{D 1969}$$

$$+ \underset{(4.55)}{0.0002}\ \text{HDD} - \underset{(-0.83)}{0.03}\ \ln \text{PRICE} + \underset{(0.46)}{0.05}\ \ln \text{WAGE}$$

R^2 = .95   Durbin-Watson = 1.55

(4) Maryland Commercial Summer Model

$$\ln(\text{MWH/CEMP}) = \underset{(27.56)}{0.89}\ \text{LDEP} - \underset{(-0.85)}{0.03}\ \text{PRICE}$$

$$+ \underset{(0.63)}{0.06}\ \ln \text{WAGE} + \underset{(2.84)}{0.0002}\ \text{CDD} - \underset{(-3.94)}{0.74}\ \text{CH}$$

R^2 = .94   Durbin-Watson = 2.19

Table A-2 (Continued)

(5) Delaware Industrial Model

$$\ln (MWH/MEMP) = \underset{(3.47)}{1.97} + \underset{(6.07)}{0.49}\ LDEP - \underset{(-3.33)}{0.27}\ \ln PRICE$$

$$+ \underset{(1.81)}{0.56}\ \ln WAGE + \underset{(0.25)}{0.0009}\ CUL$$

R^2 = .77 Durbin-Watson = 0.80

(6) Maryland Industrial Model

$$\ln (MWH/MEMP) = \underset{(18.06)}{0.83}\ LDEP - \underset{(-1.03)}{0.05}\ \ln PRICE$$

$$\underset{(1.57)}{0.40}\ \ln WAGE + \underset{(2.24)}{0.06}\ D\ 1975$$

R^2 = .94 Durbin-Watson = 1.70

(7) Virginia Commercial/Industrial Model

$$\ln (MWH/TEMP) = \underset{(0.40)}{0.22} + \underset{(8.40)}{0.88}\ LDEP - \underset{(-1.23)}{0.08}\ \ln PRICE$$

$$\underset{(0.36)}{0.15}\ \ln WAGE + \underset{(4.51)}{0.0004}\ CDD + \underset{(1.01)}{0.00004}\ HDD$$

R^2 = .87 Durbin-Watson = 2.08

Variable Definitions

MWH	= Monthly or quarterly megawatt hour sales
CEMP, MEMP, TEMP	= Commercial, manufacturing and total employment
LDEP	= Lagged dependent variable
PRICE	= Electricity price defined as either marginal price or typical bill (inflation adjusted)
WAGE	= Manufacturing hourly wage rate (inflation adjusted)
CDD	= Cooling degree day measure
HDD	= Heating degree day measure
CUL	= Capacity utilization measure
CH	= Change in employment measure
D 1969, D 1975	= Dummy variables for 1969 and 1975

Numbers in parentheses are t-statistics.

The resultant econometric equations are noticeably different in the commercial and industrial sectors. The price and wage elasticities which are shown below as systemwide averages highlight the basic differences.

	Price		Wage Rate	
	Short-run	Long-run	Short-run	Long-run
Summer Commercial	-0.05	-0.24	0.10	0.50
Winter Commercial	-0.05	-0.29	0.06	0.37
Industrial	-0.23	-0.58	0.52	1.41

The industrial elasticities appear to be roughly in line with results obtained in other studies. The commercial elasticities are much lower, but since little econometric research has been performed in this sector it is difficult to compare these results with any sort of prevailing consensus.

Other Elements of Energy Demand

In addition to energy usage by commercial and industrial customers, there are some other elements of system energy use that must be forecasted. In the Delmarva study it was not possible to obtain customer class retail sales data from some of the municipal systems operating in Delaware. Consequently, the DP&L sales for resale to those systems and any generation by those systems were combined into one aggregated time series.

Since most of this energy is used by residential customers, it was modeled by constructing a regression model which relates this energy to Delaware residential sales and a series of monthly dummy variables. The dummies explain the extent to which this energy usage differs from DP&L residential usage with respect to seasonality and/or weather-relatedness.

The final element of energy considered in these studies is system energy losses, which on any utility system is an accounting residual measuring the difference between system output and system sales. The approach taken was first to construct a loss factor (defined as losses as a percentage of sales) and then to relate that loss factor to the industrial sector's share of total sales (ISHR) and the log of time. These relationships were estimated using annual time-series data with ordinary least squares regression. The results are shown below.

$$\text{Losses/Sales} = \underset{(5.66)}{0.12} - \underset{(-2.38)}{0.12}\ \text{ISHR} - \underset{(-0.31)}{0.0008}\ \ln \text{TIME}$$

$R^2 = .56$ Durbin-Watson = 1.94

Increases in the industrial sector's share should lower the loss factor because industrial customers receive power at high voltages. Loss factors tend to be inversely related to the voltage level. Time is intended to serve as a proxy for technological change; over time loss factors should improve. The logarithmic transformation is intended to suggest "diminishing returns" to technological change and also to insure that any forecast of an improved loss factor is modest.[1]

Peak Demand Models

The PPSP studies have forecast peak demand at the system level only. No attempt has been made to do so at the class or jurisdiction level because accurate data series on such loads are not available. Moreover, system planning is governed by system peaks rather than class or jurisdictional peaks.

Peak demand in the long-run tends to be driven by virtually the same factors that determine energy usage -- economic activity, population, energy prices, weather and so forth. Rather than directly relate those factors to system peak demand, it is far easier to utilize a total energy output variable, which accounts for all of those factors implicitly. Thus, the basic approach involved constructing regression models, for the summer and winter seasons, which relate monthly peak demand to total system energy output (i.e. sales plus losses), the industrial sector's share of total system energy output and a peak day weather variable. For a given level of total energy output, an increase in the industrial sector's share should tend to lower peak demand since the industrial sector tends to exhibit flatter loads.

The estimation of such a model appears to be rather simple and straightforward, but it is in fact complicated by swings in monthly weather. Month to month changes in weather can rather drastically affect the magnitude of the total energy output variable. However, the weather sensitivity of peak demand is properly measured by a peak day weather variable, not a monthly weather variable. To complicate matters further, monthly weather and peak day weather (using a monthly series) are likely to be highly correlated causing a multicollinearity problem between the energy (which is strongly influenced by monthly weather) and peak day weather variables in the equation. The result is that the energy variable is likely to "overexplain" peak demand, and the weather variable would "underexplain" peak demand.

The solution to this problem is to first remove the weather component of the monthly energy usage variable. To do this a set of equations were econometrically estimated which related total monthly energy output to a trend measure and to monthly weather. Using the resultant coefficients and monthly weather values, the weather sensitive component was removed.

Thus, the peak demand estimating equations, which are shown in Table A-3, relate monthly peak demand to non-weather sensitive energy, the industrial sector's share of non-weather sensitive energy and peak day weather. These models were estimated from monthly time series covering the period 1966-1977. After examining residuals from initial regression results, it was found that the models produced some small but systematic error for August and January. To correct the problem, dummy variables were inserted for those months.

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[1] Without such transformation the model might forecast unrealistic loss factor improvements a number of years into the future.

Table A-3

Delmarva Peak Demand Models

<u>Summer</u>

$$\ln(MW) = \underset{(-13.08)}{-9.94} + \underset{(30.89)}{1.04}\ \ln MWH - \underset{(-4.54)}{0.30}\ \ln ISHR$$

$$+ \underset{(7.84)}{1.03}\ \ln WEATHER - \underset{(-2.21)}{0.03}\ AUGUST$$

$R^2 = .98$ Durbin-Watson = 1.62

<u>Winter</u>

$$\ln(MW) = \underset{(-7.45)}{-4.37} + \underset{(30.59)}{0.95}\ \ln MWH - \underset{(-8.46)}{0.005}\ WEATHER$$

$$- \underset{(-3.83)}{0.25}\ \ln ISHR - \underset{(-2.67)}{0.04}\ JANUARY$$

$R^2 = .97$ Durbin-Watson = 2.36

<u>Variable Definitions</u>

MW	= Monthly system peak demand
MWH	= Monthly system nonweather sensitive outputs
ISHR	= Industrial sector's share of nonweather sensitive monthly system energy output
WEATHER	= Peak day weather variable.
AUGUST, JANUARY	= Dummy variables for those months.

Numbers in parentheses are t-statistics.

Backcast Checks

As judged by the R^2's, the Delmarva energy and peak demand regression equations were able to explain power demands rather accurately. This was further examined by the calculation of "backcasts." Backcasts are obtained by inserting actual values of each of the independent variables into the estimated model and then calculating the values of the dependent variable. The simulated or backcasted sales (or peak demand) figure can be obtained for each historical month or year and compared to actual experience in order to judge the accuracy of the model -- at least for that period.

A summary of backcast and actual comparisons is shown in Table A-4 for the Delmarva study. These errors are averaged over selected time periods on both a simple averaging basis and an absolute averaging basis. The purpose of the absolute average is to demonstrate the degree of accuracy in explaining the historical data. The percent error figures were converted to absolute values before taking the average so that the positive and negative values do not cancel each other out. These results indicate average errors of about one to two percent and almost no perceptible difference by time periods. The simple average measures permit positive and negative errors to cancel. This measure can be used to determine if models systematically underestimate demand during certain periods (e.g., 1967-1973) and overestimate demand during others (e.g., 1974-1977). All of the simple average figures in Table A-4 are extremely small (because of offsetting errors within time periods), and there appears to be no systematic tendency for differences in results by time period. Thus, Table A-4 indicates that the models appear to explain the early years of the data base as well as they do the later years.

Table A-4

Delmarva Peninsula

Average Differences Between Backcast and

Actual Power Demands (Percentages)

Time Period	Residential Absolute Average (a)	Residential Simple Average (b)	Commercial Absolute Average (a)	Commercial Simple Average (b)	Industrial Absolute Average (a)	Industrial Simple Average (b)	Summer Peak Absolute Average (a)	Summer Peak Simple Average (b)
1967 - 1977	1.35%	0.22%	1.29%	-0.01%	2.56%	-0.03%	1.96%	-1.10%
1967 - 1973	0.93	0.57	0.54	-0.11	3.25	-0.32	2.46	-2.38
1974 - 1977	2.09	-0.40	2.60	0.17	1.35	0.46	1.56	1.14
1975 - 1977	1.61	0.64	1.85	1.85	1.42	1.00	1.04	0.48

(a) The absolute value of the percent backcast error for each year of the specified time period is first obtained, and the average of those figures for that time period is then computed.

(b) The percent backcast error for each year of the specified time period is first obtained, and the average of those figures for that time period is then computed. This differs from the "absolute average" in that positive and negative percent errors are permitted to cancel each other in in the averaging process.

Source: (4)

C. Forecast Assumption

In order to forecast demands using the models described in Section B, it is first necessary to formulate assumptions concerning future values of all right-hand-side variables in the models. For some variables, e.g., weather, dummy variables, capacity utilization, and so forth, future values are rather obvious and do not change over the forecast period. Most other variables can only be predicted with great difficulty and uncertainty. Since the variables in question tend to be causally interrelated, it is important to develop assumptions concerning these variables that are logically consistent with one another. A set of internally consistent assumptions is referred to as a "scenario." A Most Likely Case scenario is normally developed first based upon the best available information and judgment, and then alternative scenarios are constructed in order to bracket the range of uncertainty which surrounds the Most Likely Case growth path.

Most Likely Case (MLC)

The major forecasting assumptions can be divided into four main categories:

- The size of the service area economy -- This would include such variables as employment (total and by sector), population, and number of households.
- The productivity of the service area economy -- The hourly wage rate and personal income largely reflect the productivity of the region.
- Energy prices -- This includes electricity price, and where fuel switching is relevant, price escalations for natural gas and/or oil.
- Other factors -- Assumptions must be made concerning weather, space heating and air-conditioning saturations, and capacity utilization. The treatment of dummy variables is self-explanatory.

The Delmarva study serves to illustrate the PPSP/DSP method of developing the Most Likely Case set of assumptions. For most variables, assumed growth rates were applied to the base year (i.e., 1977) values to obtain values of those variables for all future years of the forecast period. All dollar denominated variables (e.g., income, wage rate, energy prices) were escalated in inflation adjusted terms. In most cases, the economic and demographic assumptions could be obtained from official state or federal sources. In some instances official projections were only used to provide general guidance and additional analysis and judgment were applied. Finally, the methods used varied from state to state, depending upon the quality and quantity of projections data available from state governments.

Population and employment projections for Maryland counties were provided by DSP (5), and the growth rates implicit in these projections were applied in a straight-forward manner without any adjustment. The county level projections were simply aggregated to correspond to the Maryland portion of the service territory. The population growth rate was combined with the U.S. Census

Bureau's nationwide household formation rate projection to obtain a projection of the growth rate of households in the Maryland service area. The number of households is expected to grow more rapidly than population because of the tendency toward smaller size families.

The population and employment projections are also useful in obtaining projections on the service area's productivity variables -- i.e., wage rates and per capita income. Earnings per worker and the ratio of employment to population are the two main determinants of per capita income. That is, not only does per capita income depend upon earnings per worker, but it is also determined by the percentage of the population which is employed. Ignoring for the moment non labor income, the growth rate in per capita income is the sum of the growth rates of earnings per worker and the growth in the percentage of the population employed.

Over the very long term, real wage rates are governed by labor productivity advances, because real wages are the mechanism by which the economic benefit of increased productivity is reflected in labor incomes. However, neither regional wage rates nor productivity projections are available from any official source. Thus, it was assumed that the Maryland service area wage rates will grow by two percent annually based upon the U.S. Department of Labor's long-term outlook for the national economy. Finally, the income projection was obtained by adding to this two percent figure the growth in the employment/population percentage.

Undoubtedly, the most difficult variable to forecast is the price of electricity. To some extent, the U.S. Energy Information Administration's mid-term projections for electricity prices and the prices of fuels used to generate electricity -- coal and oil -- were relied upon for guidance. However, these figures are national and must be applied to any individual utility with caution. Thus, in formulating final assumptions on electricity price various factors were judgmentally considered, including expected growth in rate base resulting from scheduled capacity additions, changes in fuel mix, and past trends.

The final category of assumptions were dealt with very simply. All weather variables were assumed to equal their long-term average in all forecast years. The same assumption was made concerning capacity utilization. Assumptions concerning changes in space heat and air conditioning saturation were developed by specifying exponential "decay" rates for households not possessing those appliances. That is, households lacking those appliances are assumed to diminish by some fixed percentage each year until some theoretical maximum saturation level is achieved. These are relatively minor assumptions since the saturation variables only serve in the models to weight the weather values.

Alternative Scenarios

Alternatives to the Most Likely Case were developed to deal with the problem of assumption uncertainty and to produce a plausible range of results. In developing each scenario care was taken to ensure that the changes in assumptions were logically consistent with one another. Along with the scenarios, sensitivity tests were performed in which only one assumption change was made per forecast model run in order to determine the importance of each assumption.

The major alternative scenarios to the Most Likely Case include the following:

- High Electricity Prices -- Assume that the real price of electricity escalation rate is double the MLC for all customer classes and jurisdictions.
- Low Economic Growth -- Decrease all of the MLC projected growth rates of employment and in the number of residential customers by 0.5 percent annually, and decrease the real wage and per capita income MLC growth rates by 0.8 percent annually.
- High Electricity Prices and Low Economic Growth -- This scenario incorporates the changes to the MLC from the above two scenarios.
- High Economic Growth -- Increase MLC projected growth rates for employment and households by 0.5 percent per year and increase wage rates and per capita income by 0.8 percent per year.
- Energy Policy Scenario -- Includes anticipated effects of the National Energy Act conservation programs and the systemwide implementation of marginal cost, time-of-use rates. This scenario is discussed further in the next section.

In the Delmarva study, as in all the PPSP/DSP forecast studies, the results vary considerable from one scenario to another; the spread between the upper and lower bound results is quite large. Table A-5 presents the peak demand forecasts and annual average growth rates for each scenario in the Delmarva study. The high electricity price/low economic growth scenario serves as the lower bound, while the rapid economic growth scenario is the upper bound. The 1995 difference between the upper and lower bounds is about 1,100 megawatts, and both scenarios differ from the Most Likely Case in that year by about 500 megawatts.

Energy Policy Impacts

In October 1978 Congress passed five pieces of legislation known collectively as the National Energy Act. This legislation increased federal involvement in and regulation of the energy sector and mandated several major conservation programs. Some of the programs, such as the appliance efficiency standards, serve to regulate the way in which energy is used. Many others involve very substantial grants or tax incentives to encourage conservation and renewable resources. The Public Utilities Regulatory Policies Act requires state commissions to consider the appropriateness of marginal cost, time-of-use pricing of electricity.

None of the programs were considered in the Most Likely Case because the econometric models could not be directly structured to accommodate these programs. Thus, methods were employed to determine program impacts outside the framework of the Delmarva models.

Table A-5

Peak Demand Forecasts For The Most Likely Case And Alternative Scenarios

-- Delmarva Study (Megawatts)

	Most Likely	High Price	Low Economic Growth	High Price/ Low Growth	High Economic Growth	Energy Policy
1980	1,645	1,639	1,608	1,602	1,682	1,645
1985	1,979	1,872	1,788	1,745	2,060	1,871
1990	2,246	2,163	1,983	1,912	2,545	2,150
1995	2,632	2,504	2,198	2,096	3,156	2,504
			Annual Rates of Growth			
1980-1995	3.19%	2.87%	2.11%	1.81%	4.29%	2.85%

Source: (4)

Because of the great uncertainty associated with both the future of these programs and their impacts, none of these results are included in the Most Likely Case forecasts. They are listed instead as a separate scenario.

Using the Oak Ridge National Laboratory integrated economic/engineering model of energy usage, the Energy Information Administration has made estimates of national electric energy savings from National Energy Act conservation programs. The Oak Ridge model is able to determine energy usage reductions net of what would have been induced by rising electric rates. Virtually all of the conservation programs included in their analysis relate to the residential and commercial sectors. By 1990, Oak Ridge estimates nonindustrial electric energy usage reductions of roughly seven percent as compared to their base case. For Delmarva, this translates into a 180 megawatt reduction in peak demand assuming that conservation programs are neutral with respect to time of use of electricity.

The Delmarva study also includes an analysis of the potential peak demand reductions from marginal cost, time-of-use pricing. It was assumed that these rates will have no effect on total energy consumption but only the time pattern of consumption. The impact on peak demand growth was determined by applying the price elasticities from the econometric models to differentials in peak/off-peak costs which were obtained from a recent marginal cost study of the Delmarva system. To obtain conservative impact estimates, it was assumed that the demand at the time of the system peak is less price elastic (i.e., price responsive) than overall energy use. Using this approach, it was estimated that systemwide implementation of time-of-use pricing might save as much as 130 megawatts of peak demand by 1995.

Monthly Adjustments to Energy Models

Since energy sales serve as an input to the forecast of peak demand, it is necessary that each of the various energy models be capable of producing a long-range forecast for each month of the year. The major concern in producing monthly forecasts is to ensure that the forecasted monthly pattern or allocation of annual sales is realistic. For the most part, the only right hand variable which is capable of generating monthly differences in energy usage is the weather. Other factors may also systematically influence the monthly energy sales pattern, but these factors were excluded from the models either because they could not be quantified, could not be identified, or would have introduced an unacceptable degree of multicollinearity.

A technique was utilized in the Delmarva study which assures that the monthly historical sales accurately reflects the historical pattern. For each of the energy forecasting models, residuals were computed from the econometric equations and regressed against a series of monthly (or quarterly in the industrial sector) dummy variables. The estimated coefficients on the dummies represent the average statistical error (after permitting positives and negatives to cancel) in the application of each of the models to the various months. The residual coefficients (or means) and dummy variables were then incorporated into the final forecasting models to obtain the monthly forecasts.

The results from this procedure indicate that for most equations and most months there is no significant tendency to over or underestimate energy usage. In a few instances the average error is as much as two to three percent; but in most cases it was less than one percent.

The analysis of residuals assures that the monthly pattern of usage per employee or per customer will be satisfactorily adjusted. However, to ensure that total energy sales reflect the proper monthly pattern, the patterns of employment and residential customers must be maintained. To this end, the projections on customers and employment were adjusted to fit the average monthly pattern in those variables which prevailed over the period 1972-1977.

D. Forecast Results For The Other Companies

As a means of presenting the PPSP/DSP approach to load forecasting, this Appendix has used the Delmarva study as an example. This section provides a summary of the forecast results for the other three major utilities -- APS, Pepco and BG&E. Since updates have been performed for all three utilities, both the original and the latest PPSP forecasts are provided for comparison. Although the original studies all included several alternative scenarios, the udpates only provide a Most Likely Case forecast.

Table A-6 provides the results for the Most Likely Case and five alternative scenarios from the original forecast study for APS. Along with the various economic scenarios, the last column of the table incorporates the potential impact upon peak demand from time-of-use pricing. This table indicates that the upper and lower bounds have forecasted annual rates of growth which differ from the Most Likely Case by approximately a percentage point.

Table A-7 presents forecasted peak demand growth rates for BG&E, Pepco and APS from the original studies and updates for purposes of comparison. As this table indicates, the update results are substantially below the original forecasts in every case. There are two basic causes of the forecast reduction. First, late 1970's load growth was far less than anticipated, by both the Companies and PPSP. Second, the outlook for economic growth in the service areas of these utilities has become less optimistic. Although downward revisions to the orginal forecasts are clearly warranted, the new forecast studies which will be prepared by PPSP in the near future should provide more reliable results.

Table A-6

Peak Demand Forecasts For The Most Likely Case and Alternative Scenarios

-- The Allegheny Power System (Megawatts)

	Most Likely	Rapid Growth/ Low Price	Rapid Growth	Slow Growth	Slow Growth/ High Price	Time of Use Pricing
1980	5,648	5,902	5,775	5,521	5,340	5,648
1985	6,867	7,432	7,141	6,548	6,050	6,579
1990	8,156	9,386	8,732	7,565	7,015	7,592
1995	9,601	11,441	10,612	8,757	8,117	8,820
			Annual Rates of Growth			
1980-1995	3.60%	4.51%	4.14%	3.12%	2.83%	3.02%

Source: (3)

Table A-7

Original And Revised Peak Demand Forecasts For
APS, PEPCO And BG&E
(Megawatts)

	APS		Pepco		BG&E	
	Original	Revision	Original	Revision	Original	Revision
1980	5,648	5,272	4,452	4,142	3,510	3,770
1985	6,687	6,093	5,621	4,393	4,418	4,447
1990	8,156	7,000	--	4,554	5,543	5,232
1995	9,601	7,984	--	--	--	5,965
			Annual Rates of Growth			
1980 - 1995*	3.60%	2.81%	4.77%	0.95%	4.68%	3.11%

* Growth rates, based upon 1995 or last year of the forecast period.

Source: (3), (6), (1), (7), (8)

REFERENCES - APPENDIX A

(1) Wilson, John W., Douglas Point Site. Maryland Power Plant Siting Program, PPSE 4-2, Volume 3. July 1975.

(2) J.W. Wilson & Associates, Inc., Projected Electric Power Demands for the Baltimore Gas & Electric Company, Maryland Power Plant Siting Program, PPES-1. 1979.

(3) J.W. Wilson & Associates, Inc. Projected Electric Power Demands for the Allegheny Power System. Maryland Power Plant Siting Program, PPES-2. January 1980.

(4) J.W. Wilson & Associates, Inc., An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula. Maryland Power Plant Siting Program, PPES-3. March 1980.

(5) Maryland Department of State Planning, Population and Employment, 1975-1990. May 1978 Revisions.

(6) Kahal, Matthew I., Additional Direct Testimony of Matthew I. Kahal on behalf of the Maryland Power Plant Siting Program. November 12, 1981.

(7) Maryland Power Plant Siting Program, Ten Year Forecast of Energy and Peak Demand for Maryland Electric Utilities, 1981-1990. Maryland Department of Natural Resources (in conjunction with the Maryland Department of State Planning). November 1980.

(8) Kahal, Matthew I. (Exeter Associates, Inc.). Memorandum to Howard A. Mueller (PPSP). July 15, 1981.

APPENDIX B

STATUS OF POWER PLANTS UNDER THERMAL
DISCHARGE REGULATIONS

APPENDIX B

STATUS OF POWER PLANTS UNDER THERMAL DISCHARGE REGULATIONS

Plant	Mixing Zone Criteria	Spawning and Nursery Area of Consequence	Status
Calvert Cliffs	Passes	PPSP recommends passage	Approved 12/81
Chalk Point	Fails	Under review	Draft impact report submitted by BG&E; undergoing review
Crane	Fails	Under review	Draft impact report submitted by BG&E; undergoing review
Dickerson	Fails (under some flow conditions)	PPSP recommends passage	PPSP recommendation of acceptable impact submitted 4/81; final hearing scheduled 2/82
Gould Street	Passes	Passes	PPSP recommendation submitted 10/81 to DHMH, awaiting EPA/OEP review
Morgantown	Passes	PPSP recommends passage	Approved 8/81
R.P. Smith	Fails (under some flow conditions)	PPSP recommends passage	PPSP recommendation submitted 5/81 to DHMH; awaiting hearing schedule
Wagner	Fails	Under review	Awaiting action for further studies

THE 1982 TEN YEAR PLAN

OF

MARYLAND ELECTRIC UTILITIES

PROPOSED AND PLANNED NEW POWER PLANTS

1982 THROUGH 1991

Prepared For:

POWER PLANT SITING PROGRAM
DEPARTMENT OF NATURAL RESOURCES

By:

ENGINEERING DIVISION
PUBLIC SERVICE COMMISSION OF MARYLAND
AMERICAN BUILDING
231 E. BALTIMORE STREET
BALTIMORE, MARYLAND 21202

NOVEMBER, 1981

TABLE OF CONTENTS

I. INTRODUCTION

This Report constitutes the 1982 Ten-Year Plan of the Public Service Commission of Maryland (referred herein as the Commission) regarding those planned and proposed sites, including associated transmission routes, of new electric power plants within the State of Maryland. This report is prepared in compliance with Section 54B(b) of Article 78 of the Annotated Code of Maryland. (See Attachment No. 1) The plans herein are based upon the long-range plans submitted annually by the individual electric utilities, with supporting analyses and information by the Engineering Division of the Commission.

Although the primary thrust of this Report is on new generating plants planned for just the State of Maryland, it should be recognized that three of the four major electric utilities operating in the State are multi-jurisdictional. Planning by these utilities is on a system-wide basis to provide generation capacity to meet the needs of their entire service area.

For this reason, this Report also provides data on projected system demands and new generation planned outside Maryland. Unit retirements are not listed although they are available in the individual utility plans.

II. UTILITIES IDENTIFIED

The 14 retail electric companies presently operating in Maryland and subject to the jurisdiction of the Commission are listed in Attachment No. 2, according to type of ownership: investor-owned, municipally-owned, and customer-owned (i.e., cooperatives).

In addition, 2 non-retail electric companies own generation property in Maryland. They are:

1. Pennsylvania Electric Company owns a hydro-electric plant on the Youghiogheny River, Garrett County (Deep Creek Lake Reservoir) and an associated transmission line into Pennsylvania.
2. Susquehanna Power Company, a wholly-owned subsidiary of Philadelphia Electric Company, owns the Conowingo hydro-electric plant on the Susquehanna River, Harford and Cecil Counties, and an associated transmission line. Operation of this plant is by the Susquehanna Electric Company under a long-term lease with Susquehanna Power Company.

Of these 14 companies, only the 7 utilities listed below have future power plant siting interests in Maryland:

Baltimore Gas and Electric Company
Conowingo Power Company
Delmarva Power and Light Company
Easton Utilities Commission
The Potomac Edison Company
Potomac Electric Power Company
Southern Maryland Electric Cooperative, Inc.

Of these 7 companies, 2 companies, Conowingo Power Company and Southern Maryland Electric Cooperative, own no generation plant at the present time. Some of the other Maryland utilities may have partial interests in generating plants outside the State.

III. 1982 TEN-YEAR SITING PLANS, BY COMPANY

General

These Plans reported herein reflect continued uncertainties by the electric utility industry in the demand for electricity, and in the amount and type of generation capacity required to reliably meet that demand. During the past 7 years, a number of events have occurred which have had and are having a significant influence on peak demand, such as the economic recession of 1974-75, the continued high rate of inflation, the escalating costs of all forms of energy, increased awareness for the need for energy conservation, and spiraling costs of new generation plant. Clouding the nuclear option has been the recent accident at Three Mile Island.

The estimates of peak demand contained herein have been provided by the individual utilities. It is anticipated that a review of the methodologies used will be undertaken at a later date.

A discussion of the individual company plans is provided below.

1. Baltimore Gas and Electric Company

In 1973, the Company was granted approval by the Commission to begin construction of two 620-MW coal-fueled steam units at Brandon Shores, near Hawkins Point, Anne Arundel County. Unit One is scheduled to begin operational service in May, 1984. The second unit will become operational in January, 1988. These same operational dates were reported in last year's Plans.

Additional generation capacity is being planned as an extension to the Safe Harbor Water Power Corporation hydro-electric plant in Pennsylvania. This plant has a present capacity of 228-MW. It is located on the Susquehanna River, Lancaster County, Pennsylvania, approximately 20 miles upstream from the Pennsylvania-Maryland border.

The Safe Harbor Water Power Corporation is wholly owned by the Baltimore Gas and Electric Company and the Pennsylvania Power and Light Company. The entitlement to the present plant's capacity and energy is:

Baltimore Gas and Electric Company	152-MW	(66.67%)
Pennsylvania Power and Light Company	76-MW	(33.33%)
TOTAL	228-MW	(100.00%)

The expansion already approved by the Federal Energy Regulatory Commission will consist of 4 additional turbine units, each of 37.5-MW, for a total added capacity of 150-MW. Of this, Baltimore Gas and Electric Company will receive 100-MW.

Approval of a fifth turbine unit (37.5-MW) by the Federal Energy Regulatory Commission is being awaited, pending completion of minimum flow studies of the Susquehanna River.

This approved expansion, as well as the fifth new unit, will have an in-service date of Fall, 1985. Construction is scheduled to start in the Fall of 1982. Baltimore Gas and Electric Company will not require any reinforcements of the existing transmission line from this plant.

Projects which will go on-line in the years following the 1982-1991 decade require planning, site work, regulatory approval and licensing within this ten-year period. The Company is considering new generation subsequent to 1991 to include the construction of a large fossil-fueled unit at its Perryman site in Harford County, Maryland. It would become operational in the early to mid-1990's. The technology choice, including the kind of fuel and unit size, are currently under study. There may be joint ownership with a neighboring utility.

Also being studied for the mid to late 1990's is a hydro pumped storage plant. Studies by the Company have shown this technology to be an attractive way to generate power during times of peak demand. The Company is looking for another utility for joint participation. There is no indication as to its location.

2. Conowingo Power Company

The Conowingo Power Company is a wholly-owned subsidiary of The Philadelphia Electric Company. Conowingo Power Company is operated as an integral part of the Philadelphia Electric system, and so enjoys the benefits of being part of the larger system and of the PJM Interconnection, of which Philadelphia Electric is a member.

Almost all of the Philadelphia Electric system generation plant is located in Pennsylvania. The Conowingo hydro-electric plant on the Susquehanna River in Maryland has 474-MW installed capacity. It represents about 7% of the Philadelphia Electric's total installed capacity.

Philadelphia Electric Company owns two sites in Maryland for future power plant development. The 680 acre Canal site is located on the Chesapeake and Delaware Canal approximately one mile west of the town of Chesapeake City, Cecil County, Maryland.

The other site, known as Seneca Point, contains approximately 560 acres which Philadelphia Electric Company owns for future power plant development. It is located on the west bank of the Northeast River, approximately one mile southwest of Charlestown, Cecil County, Maryland.

There are no plans for Philadelphia Electric Company to start construction on either of the above sites within the next ten years.

3. Delmarva Power and Light Company

In April, 1978, Delmarva filed an Application with the Commission for the construction of a new 400-MW coal-fired steam generation unit as an extension to its existing generation plant at Vienna, Dorchester County, Maryland. By a letter to the Commission in July, 1979, Delmarva modified its original Application to increase the size of the unit to 500-600-MW nominal. Its exact size will depend on ultimate ownership and each owner's degree of participation.

Delmarva anticipates shared ownership of this unit, known as Vienna #9, as follows:

Delmarva	325-MW	(65%)
Atlantic City Electric Co.	125-MW	(25%)
Old Dominion Electric Co.	50-MW	(10%)
Total	500-MW	(100%)

Delmarva will be responsible for the licensing, construction and operation of this unit. It is expected to be operational in 1990. Actual construction start is presently planned for 1986.

No new transmission lines associated with this new unit will be required. However, several existing bulk power lines will be upgraded to 230-KV operation.

The Commission's Hearing Examiners Division issued a Proposed Order granting a Certificate of Public Convenience and Necessity to Delmarva for the construction of this unit on October 30, 1981. Additional details concerning this unit will be found in Commission Case No. 7222 which dockets this proceeding.

Two sites on the eastern shore, identified and evaluated by the Maryland Power Plant Siting Program in a recent study* appear suitable for use by Delmarva as possible sites. The Church Creek site, in Dorchester County, is just east of Church Creek and approximately 5 miles southwest of Cambridge along Maryland Route 16. The Deep Branch site is in southwestern Wicomico County about 3 miles west of the Nanticoke River at the Bivalve community, and north of the Wicomico River at its junction with Wicomico Creek.

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*Eastern Shore Power Plant Siting Study, Vol. 2, Maryland Major Facilities Studies, October, 1977 PPSA-4

4. <u>Easton Utilities Commission</u>

In 1975, the Public Service Commission granted Easton Utilities Commission a Certificate of Public Convenience and Necessity for the construction of a new generating plant, to be known as Plant #2. This plant is located on a Town-owned 7 acre site within the city limits of Easton. The first two units of this Plant, having a total capacity of 12.5-MW, are in commercial operation.

Additional generation of 12.5-MW is planned for Plant #2 with commercial start-up in 1990. Prime mover of all units will be diesel engines, fueled by either No. 2 fuel oil or natural gas.

5. <u>The Potomac Edison Company</u>

The Potomac Edison Company is one of three operating subsidiaries of the Allegheny Power System. Potomac Edison together with its sister utilities Monongahela Power Company and West Penn Power Company are operated as one integrated facility. Most of the generation facilities of the Allegheny Power System are in Pennsylvania and West Virginia.

The Potomac Edison Company owns one site in Maryland for possible future power generation. This site, containing 829 acres, is approximately 2 miles downstream from the town of Point of Rocks, Frederick County, Maryland on the north side of the Potomac River. This site is one of several sites which are being evaluated for a coal-fired station with an in-service date in the mid-1990's.

Several other potential power generating sites in Maryland have been identified in an Allegheny Power System Siting study. A list of favorable candidate areas has been given to the Power Plant Siting Program which is currently performing a Western Maryland Power Plant Siting study. The site selected would be coal-fired with an initial in-service date in the mid-1990's.

In October, 1980, the Virginia Electric and Power Company signed an $800 million preliminary agreement to share its 2,100-MW pumped storage hydro-electric facility in Bath County, Virginia with the Allegheny Power System. Expected APS participation in this facility may be as much as 50% through either outright purchase or lease. Scheduled for completion in 1985, this facility is the largest pumped hydro plant ever built in the United States. The Potomac Edison Company's entitlement would be 280-MW. This matter is currently in proceedings before the Commission and before the Pennsylvania Public Utilities Commission.

6. Potomac Electric Power Company

Potomac Electric Power Company expects its 600-MW Chalk Point Unit #4 to begin commercial service in 1982, the same date identified in last year's Plan.

Plans by the Company show a possible 300-MW coal-fired unit for construction at its Dickerson site. In-service date has been tentatively identified as 1993. Preliminary engineering site studies, etc. were begun in 1981 with start-up as early as 1990, if needed.

The Company's Ten-Year Plan lists a possible 2,000-MW pumped-storage hydro-electric plant at an undetermined site in Maryland. The plant would likely be a joint venture with one or more other utilities. The in-service date is not specified.

7. Southern Maryland Electric Cooperative, Inc.

The Cooperative owns a 300 acre site on the Patuxent River, St. Mary's County. This site, known as the De La Brooke Farm, is considered for possible future generation. However, no plans have been made for such use.

IV. PROJECTED GROWTH IN PEAK DEMAND IN MARYLAND

The peak demand for electricity in Maryland as projected by the major utilities is listed on a yearly basis for the next decade on Attachments No. 3 through No. 6. Also shown on these Attachments are peak demands, system-wise, for the three multi-jurisdictional utilities. Total installed capacity reflecting both the additions of new or upgraded plant and retirements of older units is also indicated.

Data on the smaller utilities, Southern Maryland Electric Cooperative, Conowingo Power Company, Easton Utilities Commission and Thurmont Municipal are shown on Attachments No. 7 and No. 8.

A summary of the average annual growth rates in peak demand by utility is provided by Attachment No. 9. Corresponding data for the 1980 and 1981 Ten-Year Plans are also shown. Attachment No. 10 is a bar chart of the peak demand growth rates.

Several observations concerning the data of Attachment No. 9 are noteworthy:

1. Baltimore Gas and Electric Company, the largest utility in Maryland, has revised downward the growth in peak demand to 2.7%. Last year it projected a 3.0% growth per year.
2. At the low end of the range of growth rates is Potomac Electric Power Company. This utility is now estimating an average growth of 1% per year in Maryland, somewhat more (1.2%) system-wise.
3. The Potomac Edison Company, the only major winter-peaking utility in the state, is estimating that its Maryland customers will be requiring a 2.6% increase in peak demand,

off sharply from its figure of 4.3% in its last year's Ten-Year Plan.

4. Delmarva Power and Light Company, also, for Maryland, has revised its projected demand significantly downward, from 3.8% per year in the 1981 Plan to 2.2% this year.

5. For the entire State, the peak demand estimate has dropped from 2.8% per year last year to this year's figure of 2.3%. As a matter of interest, a growth rate of 2.3% per year corresponds to a doubling in demand in 30 years, that is by the year 2011.

V. ASSOCIATED TRANSMISSION LINES

The transmission lines associated with the construction of new generating stations will generally operate at 115-KV and higher voltages. They will require rights-of-way widths of 150 to 300 feet. An "associated transmission line", with respect to Section 54B of Article 78, refers to the means of transporting electric power from a power plant to one or more points on an existing transmission system. Such lines are often called "generation leads". There are also "transmission lines", with respect to Section 54A of Article 78, which are not "generation leads" but rather they provide substation-to-substation bulk power transmission for increased capacity or reliability purposes. In any of these instances, the long-range need and probable capacity of a future transmission line can be determined from extensive system studies. However, the actual route and often the actual terminal location(s) of a line can be established only after subsequent years of planning and surveys.

Lines planned for possible construction at later dates and in particular the "associated transmission lines" for new power plants cannot be defined as to specific siting. However, general planning information regarding terminal points, voltage levels and dates to the extent possible is contained in the individual plans submitted by the major companies.

VI. POWER PLANT SITING PROGRAM PROJECTIONS OF UTILITY PEAK DEMAND

The Power Plant Siting Program of the Department of Natural Resources has prepared its own forecasts of annual peak demand for the four major utilities in Maryland out through 1992.

These projections, forwarded to the Public Service Commission in a letter dated November 20, 1981, are listed in Attachment No. 11. Additional details concerning the methodologies and assumptions used as a basis for these data may be obtained from Dr. Howard Mueller of the Power Plant Siting Program.

VII. FURTHER INQUIRY

In the event further inquiry is indicated, such as by other state agencies, the request should be directed to the Commission by writing to Mrs. Gloria Jimenez, Executive Director. Specific information requests of an engineering nature and comments on this Plan should be directed to Mr. John W. Dorsey, Chief Engineer, or to its author, Mr. Richard M. Hollis, Senior Engineer.

ATTACHMENT NO. 1

SECTION 54B(b), ARTICLE 78 OF THE ANNOTATED CODE OF MARYLAND

"§ 54B. Consolidated public hearing, long-range plans and establishing an environmental surcharge on generated electric energy; notice to landowners over whose property company intends to run line, etc.; purchase of power plant site by State.

(b) In cooperation with the Secretary of Natural Resources as set forth in §3-304 of the Natural Resources Article of the Code, the Commission shall be responsible for assembling and evaluating annually the long-range plans of Maryland's public electric utilities regarding generating needs and means for meeting those needs. The chairman of the Public Service Commission shall, on an annual basis, forward to the Secretary of Natural Resources a ten-year (10) plan listing possible and proposed sites, including associated transmission routes, for the construction of electric power plants within the State of Maryland. Sites which are identified as unsuitable by the Secretary of Natural Resources in accordance with the requirements of §3-304 of the Natural Resources Article of the Code shall be deleted from the plan, provided, however, nothing in this subsection shall prevent the inclusion of such site in subsequent ten-year (10) plans. The first ten-year (10) plan shall be submitted on or about January 1, 1972."

ATTACHMENT NO. 2

RETAIL ELECTRIC COMPANIES OPERATING IN MARYLAND

NAME	ADDRESS	TELEPHONE NO.
Investor-Owned		
Baltimore Gas and Electric Company	Gas and Electric Building Baltimore, MD 21203	234-5000
Conowingo Power Company	211 North Street Elkton, MD 21921	398-1400
Delmarva Power and Light Company	P. O. Box 1739 Salisbury, MD 21801	749-6111
Potomac Edison Company, The	Downsville Pike Hagerstown, MD 21740	731-3400
Potomac Electric Power Company	1900 Pennsylvania Ave., N.W. Washington, D. C. 20006	(202)872-2449
Municipally-Owned		
Berlin, Mayor and Council of	P. O. Box 235 Berlin, MD 21811	641-2770
Easton Utilities Commission, The	11 S. Harrison Street Easton, MD 21601	822-6110
Hagerstown Municipal Electric Light Plant	Hagerstown, MD 21740	731-2600
Thurmont Municipal Light Co.	P. O. Box 385 Thurmont, MD 21788	271-7313
Williamsport, Mayor and Council of	Williamsport, MD 21795	223-7711
Customer-Owned		
A and N Electric Cooperative	Parksley, Virginia 23421	(804)665-5116
Choptank Electric Cooperative, Inc.	P. O. Box 430 Denton, MD 21629	479-0380
Somerset Rural Electric Coop., Inc.	P. O. Box 270 Industrial Park Somerset, Pennsylvania 15501	(814)445-4106
Southern Maryland Electric Coop., Inc.	Hughesville, MD 20637	274-3111

ATTACHMENT NO. 3

PROJECTED PEAK LOAD, CAPACITY, AND RESERVE ESTIMATES
BALTIMORE GAS AND ELECTRIC COMPANY

YEAR	PROJECTED CONTRACT* LOAD (MW)	TOTAL INSTALLED CAPACITY, (MW)	INSTALLED RESERVE MARGIN (PERCENT)
1982	4130	5025	21.7
1983	4260	5025	18.0
1984	4390	5634	28.3
1985	4530	5634	24.4
1986	4640	5759	24.1
1987	4740	5701	20.3
1988	4870	6321	29.8
1989	5000	6321	26.4
1990	5130	6321	23.2
1991	5260	6321	20.2

Average Annual Compound Growth, Percent, 2.7 in Peak Load

*Contract load represents the total demand on the Company including only that part to Bethlehem Steel which cannot be supplied by the Bethlehem generating capacity itself. The Company also reports a Group Load which represents the total electrical requirements of the Company and of Bethlehem Steel.

ATTACHMENT NO. 4

PROJECTED PEAK LOAD, CAPACITY, AND RESERVE ESTIMATES
POTOMAC ELECTRIC POWER COMPANY

	SYSTEM			MARYLAND COMPONENT*
YEAR	PROJECTED PEAK LOAD (MW)	TOTAL INSTALLED CAPACITY (MW)	INSTALLED RESERVE MARGIN (PERCENT)	PROJECTED PEAK DEMAND (MW)
1981	3912	4999	27.8	2152
1982	3956	4996	26.3	2167
1983	4000	5322	33.0	2182
1984	4058	5322	31.1	2214
1985	4105	5322	29.6	2235
1986	4153	5322	28.1	2254
1987	4208	5322	26.5	2280
1988	4259	5322	25.0	2309
1989	4302	5322	23.7	2326
1990	4355	5148	18.2	2344
1991**	Not Available (N.A.)	N.A.	N.A.	N.A.
Average Annual Compound Growth, Percent (1981-1990 Period)	1.2			1.0

*These data include Southern Maryland Electric Cooperative projected peak demand.

**PEPCO estimates for 1991 were not available at the time this report was prepared. It is anticipated that approved figures through 1991 will be made available in early 1982, and distribution of revised figures made at that time to recipients of the Commission's 1982 Plan.

ATTACHMENT NO. 5

PROJECTED PEAK LOAD, CAPACITY AND RESERVE ESTIMATES
THE POTOMAC EDISON COMPANY

YEAR WINTER OF	SYSTEM PEAK LOAD (MW)	SYSTEM INSTALLED CAPACITY (MW)	SYSTEM INSTALLED RESERVE MARGIN (Percent)	MARYLAND COMPONENT PEAK LOAD (MW)
1982/83	1585	1882	18.7	1024
1983/84	1630	1882	15.5	1046
1984/85	1694	1882	11.1	1081
1985/86	1741	1999	14.8	1116
1986/87	1822	2117	16.2	1147
1987/88	1881	2117	12.5	1174
1988/89	1932	2117	9.6	1199
1989/90	1968	2281	15.9	1226
1990/91	2050	2242	9.4	1260
1991/92	2113	2405	13.8	1295
Average Annual Compound Growth, Percent in Peak Loads	3.2			2.6

ATTACHMENT NO. 6

PROJECTED PEAK LOAD, CAPACITY AND RESERVE ESTIMATES

DELMARVA POWER AND LIGHT COMPANY

	SYSTEM			MARYLAND COMPONENT
YEAR	PROJECTED PEAK LOAD (MW)	TOTAL INSTALLED CAPACITY (MW)	INSTALLED RESERVE MARTIN (PERCENT)	PROJECTED PEAK DEMAND (MW)
1982	1,627	2,324	42.8	452
1983	1,667	2,167	30.0	457
1984	1,711	2,167	26.6	467
1985	1,767	2,217	25.5	480
1986	1,808	2,217	22.6	490
1987	1,818	2,177	19.7	503
1988	1,870	2,177	16.4	516
1989	1,919	2,177	13.4	528
1990	1,918*	2,460	28.3	517**
1991	1.964*	2,560	29.7	528**

Average Annual 2.4 — 2.2
Compound Growth (Percent), 1982-1989 Period in Peak Loads

*These figures reflect a 50-MW reduction in peak REA Cooperative load due to the proposed assumption of responsibility as a result of participation in Vienna #9 by Old Dominion.

**These figures reflect a 22-MW reduction in the peak load of the Maryland Component due to participation by Old Dominion in Vienna #9, (*) above.

ATTACHMENT NO. 7

PROJECTED PEAK LOAD

SOUTHERN MARYLAND ELECTRIC COOPERATIVE, INC.

YEAR	PEAK LOAD (MW)
1982	282
1983	300
1984	316
1985	333
1986	348
1987	366
1988	383
1989	398
1990	414
1991	428

Average Annual Compound Growth, Percent - 4.7

ATTACHMENT NO. 8

PROJECTED PEAK LOADS

CONOWINGO POWER COMPANY
EASTON UTILITIES COMMISSION
THURMONT MUNICIPAL LIGHT COMPANY

	PEAK LOAD (MW)		
YEAR	CONOWINGO	EASTON	THURMONT
1982	95	26.3	7.5
1983	97	27.1	7.9
1984	100	28.0	8.3
1985	102	28.9	8.7
1986	105	29.8	9.1
1987	107	30.7	9.5
1988	110	31.7	9.9
1989	113	32.7	10.3
1990	116	33.7	10.7
1991	119	34.8	11.1
Average Annual Compound Growth, Percent -	2.5	3.2	4.5

ATTACHMENT NO. 9

COMPARISON OF PROJECTED AVERAGE ANNUAL COMPOUND GROWTH RATES IN PEAK DEMAND FOR ELECTRICITY (PERCENT PER YEAR)

	1980 PLAN (1980-1989)	1981 PLAN (1981-1990)	1982 PLAN (1982-1991)
Baltimore Metro			
Baltimore Gas and Electric Company	3.5	3.0	2.7
Washington Metro			
Potomac Electric Power Company			
(Maryland Only)	N/A	1.2	1.0
(System)	1.9	1.2	1.2
Western Maryland			
Potomac Edison Company			
(Maryland Only)	4.4	4.3	2.6**
(System)	N/A	4.8	3.2**
Southern Maryland			
Southern Maryland Electric Coop., Inc.	4.0	4.8	4.7
Eastern Shore			
Conowingo Power Company	4.0	3.0	2.5
Delmarva Power and Light Company			
(Maryland Only)	4.1	3.8	2.2*
(System)	N/A	2.4	2.4*
Easton Utilities Commission	5.4	5.5	3.2
Entire State	3.0	2.8	2.3*

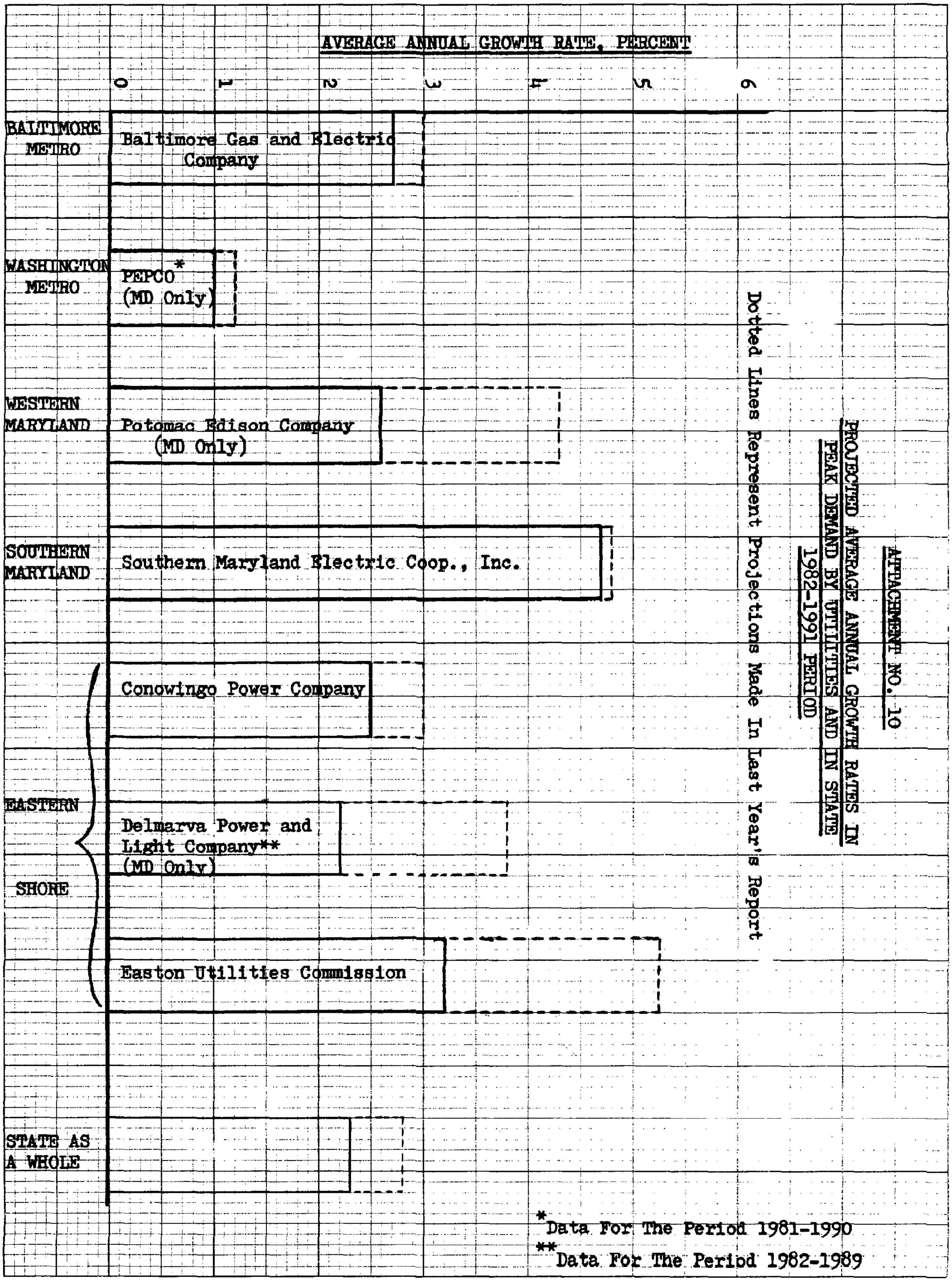
*Average Over 1982-1989 Time Period

**Average Over 1981-1990 Time Period

ATTACHMENT NO. 10

PROJECTED AVERAGE ANNUAL GROWTH RATES IN PEAK DEMAND BY UTILITIES AND IN STATE

1982-1991 PERIOD



ATTACHMENT NO. 11

POWER PLANT SITING PROGRAM PROJECTIONS
OF
UTILITY PEAK DEMAND, 1982-1992 PERIOD
(MW)

YEAR	POTOMAC EDISON* TOTAL SYSTEM	POTOMAC EDISON* MD. ONLY	DELMARVA P. & L.** TOTAL SYSTEM	DELMARVA P. & L.** MD. ONLY	PEPCO TOTAL SYSTEM	BG & E
1982	1,544	988	1,619	454	4,284	4,028
1983	1,600	1,024	1,671	468	4,322	4,162
1984	1,657	1,061	1,728	485	4,358	4,303
1985	1,717	1,099	1,790	503	4,393	4,447
1986	1,775	1,136	1,844	518	4,420	4,591
1987	1,834	1,174	1,902	535	4,453	4,741
1988	1,895	1,213	1,963	553	4,486	4,897
1989	1,958	1,253	2,027	572	4,520	5,091
1990	2,023	1,295	2,094	592	4,554	5,232
1991	2,088	1,337	2,160	612	4,580	5,372
1992	Not Available	Not Available	2,229	634	4,623	5,513
Average Annual Compound Growth Rate (Percent)	3.4	3.4	3.2	3.4	0.8	3.2

*Potomac Edison is a winter peaking utility. The peak indicated for, say 1982, is that projected for the winter of 1981/1982.

**Data includes portions of the Dover, Delaware and Easton, Maryland loads served by Delmarva at the time of the annual peak.